our ultimate goal of the 30 ppm standard in an orderly fashion, while limiting the negative environmental consequences. The temporary nature of the ABT program would ensure that any negative consequences for Tier 2 vehicles of these higher sulfur levels (120 ppm average in 2004, 90 ppm in 2005) would be minimal. By the time that the majority of new vehicles sales would be required to meet the Tier 2 standards (2006 and beyond), average sulfur levels in gasoline would meet the 30 ppm annual average standard.

We are interested in comment on the corporate pool average values, and their associated caps. A higher pool average would obviously ease implementation (e.g., 150 ppm average with an appropriate cap in 2004, for example), but we have not proposed a higher average because of our concerns that higher in-use sulfur levels after 2004 are undesirable for emissions from Tier 2 vehicles. We request that commenters supporting higher corporate pool average values discuss how such higher values would affect in-use emission levels of Tier 2 vehicles, as well as NLEV and Tier 1 vehicles.

We also ask for comment on an alternative approach that would implement the corporate average requirement for 2004 (120 ppm) but not require compliance with the 30 ppm standard (with or without credit use) until 2005. The 120 ppm corporate pool average would continue in 2005 and the 90 ppm corporate pool average would be implemented in 2006, with the requirement to meet the 30 ppm standard (with or without credits) beginning in 2005 and extending indefinitely, consistent with the proposed program.

Finally, we request comment on whether refiners should be allowed to comply with the corporate average standards through the use of sulfur credits generated under the ABT program (within the limits of the proposed caps). This would likely render the refinery-specific standards in 2004 and 2005 unnecessary, and thus refiners would only have to comply with the per-gallon caps and corporate averages in 2004 and 2005. However, in 2006 and beyond refiners would have to meet the 30 ppm average at every refinery (with limited use of sulfur credits, to the extent that the 80 ppm cap permits).

We have proposed per-gallon caps of 300 ppm in 2004 and 180 ppm in 2005 at the refinery gate, with slightly higher caps imposed downstream (as explained in Section VI.B below). We believe that downstream caps would be necessary to ensure compliance and protect Tier 2 vehicles. At the same time, we believe caps at the refinery gate would be necessary to guarantee that the environmental goals of this program were met; the corporate and refinery averages alone wouldn't provide the full emissions reductions and environmental benefits we have estimated because, by themselves, they could allow gasoline with high sulfur levels in the system as long as the refiner offset any such high sulfur batches with very low sulfur gasoline. However, there are some arguments for eliminating the per-gallon standard at the refinery gate and simply enforcing a per-gallon cap at the retail level (or some intermediate point downstream). This approach would give refiners and blenders greater flexibility in blending occasional batches of gasoline that exceed the proposed cap standards. These refiners/blenders could sell and transport these high sulfur batches to another party who would blend down the sulfur level to make gasoline meeting the downstream caps. One shortcoming of such an approach (removing the per-gallon cap at the refinery) is that not all gasoline passes through multiple parties before ending up at the retail level; some refiners ship part or all of their production directly from refinery to retail outlet. We welcome comment on whether caps at both the refinery gate and downstream are appropriate. We also encourage your input on whether the caps we have proposed to coincide with the corporate average standards are appropriate. Keep in mind that we need some limitation on sulfur levels to protect the first Tier 2 vehicles that would begin entering the marketplace as early as the fall of 2003.

b. *Proposed Standards for Small Refiners.* As explained in the regulatory flexibility analysis discussion in Section VIII.B. of this document, we have considered the impacts of these proposed regulations on small businesses. As part of this process, we convened a Small Business Advocacy Review Panel for this proposed rulemaking, as required under the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA). The Panel was charged with reporting on the comments of small business representatives regarding the likely implications of possible control programs, and to make findings on a number of issues, including:

- A description and estimate of the number of small entities to which the proposed rule would apply;
- A description of the projected reporting, recordkeeping, and other compliance requirements of the proposed rule;
- An identification of other relevant federal rules that may duplicate, overlap, or conflict with the proposed rule; and
- A description of any significant alternatives to the proposed rule that accomplish the objectives of the proposal and that may minimize any significant economic impact of the proposed rule on small entities.

The final report of the Panel is available in the docket. The Panel concluded that small refiners were the group most likely to be negatively impacted by the proposed program. (The Panel noted that small gasoline marketers would also have to comply with some portions of a gasoline sulfur program, but did not recommend any regulatory relief for this group of small businesses.) Many of the small refiners the Panel met with indicated their belief that their businesses may close if relief were not considered due to the substantial capital and other costs required to reduce sulfur levels to the 30/80 standard. The Panel recommended that EPA solicit comments on a number of options to provide relief to small refiners, which include some or all of these provisions:

- Providing small refiners a four-to six-year period during which less stringent gasoline sulfur requirements would apply; comment was also recommended on extending this period for up to a total of 10 years.
- Basing each small refinery's gasoline sulfur limit on its individual average sulfur level based on the most recent report(s) to EPA; and
- Granting temporary hardship relief on a case-by-case basis, following the four-to six-year period of relief common to all small refiners, based on a showing of economic need.

The Panel stated its belief that additional time would allow sulfur-reduction technologies to be proven out by larger refiners, thereby reducing the risks to be incurred by small refiners who choose to incorporate these technologies. The added time would likely allow for costs of these desulfurization units to drop, thereby limiting the economic consequences for small refiners. Nationally, giving small refiners more time to comply would help ensure that cross-industry engineering and construction resources would be available. Finally, extending the compliance deadlines would provide small refiners with additional time to raise capital for infrastructure changes.

i. *What Standards Would Small Refiners Have to Meet Under Today's Proposal?*

Upon evaluating the impacts of our proposed gasoline sulfur requirements on small refiners and careful review of the Panel's recommendations, we have determined that regulatory relief in the form of delayed compliance dates is appropriate to allow small refiners to comply without disproportionate burdens. We propose that, for a period of four years after other refiners must start meeting the standards proposed in Table IV.C–2, refiners meeting clearly defined company size criteria be allowed to comply with somewhat less stringent requirements than those just described for refiners and gasoline importers. We propose to define a small refiner as any company employing no more than 1,500 employees throughout the corporation, including any subsidiaries, regardless of the number of individual gasoline-producing refineries owned by the company or the number of employees at any one refinery. This number is based on the Small Business Administration definition of a small refiner for the purposes of regulation.[49] The proposed annual average small refiner standards beginning with 2004 are shown in Table IV.C–3 below, although the cap standards begin October 1, 2003.

TABLE IV.C–3.—PROPOSED TEMPORARY GASOLINE SULFUR REQUIREMENTS FOR SMALL REFINERS IN 2004–2007

Refinery baseline sulfur level (ppm)	Temporary sulfur standards (ppm)
0 to 30 ..	Average: 30. Cap: 80.[a]
31 to 80	Average: no requirement. Cap: 80.[a]
81 to 200.	Average: baseline level. Cap: Factor of 2 above the baseline.[a]
201 and above.	Average: 200 ppm minimum, or 50% of baseline, whichever is higher, but in no event greater than 300 ppm. Cap: Factor of 1.5 above baseline level.[a]

[a] The cap standard takes effect at the refinery gate October 1, 2003.

We also propose to apply these provisions to any foreign refiner that can establish that they meet this same definition of small. Since few if any foreign refiners send all of their gasoline production to the U.S., allowing eligible small foreign refiners to meet these less restrictive standards, even on a temporary basis, would be a less restrictive requirement than it will be for small domestic gasoline producers since they may be able to send lower sulfur gasoline to the U.S. without having to incur capital expenses. Furthermore, in many cases foreign refiners are not subject to the same stringent permitting and other regulatory requirements that domestic refiners face. At the same time, we believe many foreign refiners will be installing gasoline desulfurization equipment because of the various international requirements that have been proposed and/or finalized (for example, in Europe, Canada, Japan) that require gasoline sulfur levels to be reduced to levels similar to our proposed standards and thus these companies will not avoid all of these costs. In addition, in most cases we expect importers to be the party responsible for the sulfur level of imported gasoline, and importers are not eligible for the less stringent standards applied to small refiners. Hence, the number of foreign refiners who could benefit (financially and otherwise) from gaining small refiner status is likely to be very small. However, we welcome comments on the competitive and other marketplace implications of this proposal.

We believe that these proposed small refiner standards are reasonable and that they would not conflict with our overall goals of reducing gasoline sulfur levels nationwide as soon as possible and of reducing gasoline sulfur levels sufficiently to enable and protect the emissions performance of Tier 2 vehicles. Our conclusions are based in part on the fact that only a very small volume of gasoline will be eligible for these lesser standards. We have estimated that small refiners produce approximately 2.5 percent of all gasoline in the U.S. Furthermore, of the 17 refineries that we have identified as meeting SBA's definition of small business, nine already have gasoline sulfur levels less than 90 ppm. Hence, only a very small fraction of the gasoline sold in the U.S. would take advantage of the higher small refiner standards through 2007. By the time that a large number of Tier 2 vehicles could have been impacted by residing in or traveling to areas where higher sulfur fuel is sold, the temporary exemptions for small refiners would have expired. Furthermore, in most cases, gasoline produced by small refiners is mixed with substantial amounts of other gasoline prior to retail distribution (due to the functioning of the gasoline distribution system), likely resulting in only marginal increases in overall sulfur levels. Thus, the sulfur level of gasoline actually used by Tier 2 vehicles should generally be much lower than that produced by individual small refineries who receive unique compliance standards through 2007.

As explained above, we are proposing that compliance under the proposed standards be based on a refiner's being able to show that it meets specific criteria. If a refiner were able to qualify as a small refiner under our definition, it would need to then establish a sulfur baseline for each participating refinery. For small refiners, compliance with the proposed sulfur regulations would be determined on the basis of the sulfur baseline for each refinery owned by that company. The following sections explain these proposed requirements in more detail, to supplement the information be presented above. We also explain how small refiners could obtain an additional two-year exemption upon establishing a hardship case, as well as how small foreign refiners could establish eligibility for compliance under the small refiner provisions.

ii. *Application for Small Refiner Status.*

We are proposing that refiners seeking small refiner status under our gasoline sulfur program would have to apply to us in writing no later than June 1, 2002, requesting this status. In this application, the refiner must demonstrate that as of January 1, 1999, the business and any subsidiaries, including all refining, distribution, and marketing activities, as well as any other activities worldwide, employed 1,500 or fewer employees. We are proposing that in the case of refineries owned by joint ventures, the total employment of both (all) companies would be considered in determining whether the 1,500 employee limit is reached. If a refiner that is not small as of January 1, 1999 subsequently sells part of its business and as a result has fewer than 1500 employees, it would not be eligible for a small refiner status. These provisions would provide stability to the regulated and regulatory parties and ensure that no ''gaming'' of the program occurs. However, we are also proposing that any new refinery built between January 1, 1999 and January 1, 2001, or a refinery that was not operational as of January 1, 1999, owned by a refiner that meets our proposed definition, could apply for small refiner status no later than June 1, 2002. In this case, we would consider carefully the history of the refinery and

[49] SBA uses a different definition of small refiner for the purposes of federal procurements of petroleum products, and EPA in the past has used criteria based on the processing capacity of the individual refinery and of all refineries owned by one company.

the company in determining whether it is appropriate to grant this refiner small refiner status.

We are also proposing that if a refiner with approved small refiner status later exceeds the 1,500 employee threshold without merger or acquisition, its refineries could keep their individual refinery standards. This is to avoid stifling normal company growth and is subject to our finding that the refiner did not apply for and receive the small refiner status in bad faith. An example of an inappropriate application for small refiner status would be a refiner that temporarily reduced its workforce from 1,600 employees to 1,495 employees prior to January 1, 1999, and then rehired employees after the cutoff date. This would be a bad faith attempt to avoid the intent of the rule. We are requesting comment on this provision.

At any time after June 1, 2002, a refiner with approved small refiner status could elect to cease complying with the small refiner standards and, in the next calendar year, begin complying with the standards specified in Table IV.C–2 and related provisions. However, this decision would apply to all refineries owned by that refiner and once a refiner dropped its small refiner status, it would not be eligible to be reinstated as a small refiner at some later date.

iii. *Application for a Small Refiner Sulfur Baseline.*

A qualifying small refiner could apply for an individual sulfur baseline by June 1, 2002 for any refinery owned by the company by providing a calculation of its sulfur baseline using its average gasoline sulfur level based on 1997 and 1998 production data, and the average volume of gasoline produced in these two years. The proposed regulations specify the information to be submitted to support the baseline application. The baseline calculations should include any oxygen added to the gasoline at the refinery. This application would be submitted at the same time that the refiner applied for small business status; confirmation of small business status would not be required to apply to EPA for an individual sulfur baseline. If the baseline were approved, we would assign standards to each of the company's refineries in accordance with Table IV.C.–2.

Blenders would not be eligible for the small refiner individual baselines and standards because they would not have the burden of capital costs to install desulfurization equipment, which is the primary reason for allowing small refiners to have a relaxed compliance schedule.

iv. *Volume Limitation on Use of a Small Refinery Standard.*

We are proposing that the volume of gasoline subject to the small refinery's individual standards would be limited to the volume of gasoline the refinery produced from crude oil, excluding the volume of gasoline produced using blendstocks produced at another refinery.[50]

Under this approach, the baseline volume for a small refinery would reflect only the volume of gasoline produced from crude oil during the baseline years. In addition, use of the refinery's individual baseline sulfur level during each calendar year averaging period (beginning with 2004) would be limited to the volume of gasoline that is the lesser of: (1) 105% of the baseline volume, or (2) the volume of gasoline produced during the year from crude oil. Any volume of gasoline produced during an averaging period in excess of this limitation would be subject to the standards applicable to refiners not subject to a small refiner standard. In this case, the small refiner's annual average standard would be adjusted based on the excess volume in a manner similar to the compliance baseline equation for conventional gasoline under Section 80.101(f) of Part 40 of the Code of Federal Regulations. However, the small refiner's per-gallon cap standard would not be adjusted.

This limitation would assure that small refiners receive relief only for gasoline produced from crude oil, the portion of the refinery operation requiring capital investment to meet lower sulfur standards. We are requesting comment on this provision and whether an alternative approach may be more appropriate for the stated purpose.

v. *Hardship Extensions Beyond 2007 for Small Refiners.*

Beginning January 1, 2008, all small companies' refineries would have to meet the permanent national sulfur standard of 30 ppm on average and the 80 ppm cap, except small refineries that apply for and receive a hardship extension. A hardship extension would provide the small refiner an additional two years to comply with these national standards. A hardship extension would need to be requested in writing and would specify the factors that qualify the refiner for such an extension. Factors considered for a hardship extension could include, but would not be limited to, the refiner's financial position; its efforts to procure necessary equipment and to obtain design and engineering services and construction contractors; the availability of desulfurization equipment, and any other relevant factors.

By January 1, 2010 all refiners would be required to meet the permanent national average standard and cap. We are requesting comment on the proposed hardship extension, including the factors to be considered in petitions for extension, and the proposed time periods.

vi. *What Alternative Provisions for Small Refiners Are Possible?*

We have proposed one type of program to address the needs of small refiners. We solicit comment on other options so that we can consider these options as we finalize this rule. We encourage comments. We request comment on a range of alternatives, including those listed below, which could be considered when developing unique regulatory requirements for small refiners. We specifically request that the comments address not only the economic but also the environmental implications of the alternative, relative to the program we've proposed.

- Are there alternative or additional criteria that could/should be used to define a small refiner, such as the volume of crude oil processed or the volume of gasoline produced (since the gasoline sulfur standard applies specifically to gasoline)? Other criteria may also be acceptable, such as a different employee number for qualification as a small entity, or basing the count on employees employed in gasoline production only. We welcome your recommendations. Our desire is to limit the number of companies meeting the small refiner definition in order to provide regulatory relief only to those companies that have the economic concerns unique to small businesses. If you recommend criteria other than number of employees, please comment on how those criteria can be shown to limit the number of refineries that will be eligible for the proposed relief.
- Are the caps and averages of the proposed interim standards for small refiners (see Table IV.C.–3) appropriate for the corresponding individual sulfur baseline levels?
- What is an appropriate and sufficient time period for the proposed small refiner interim standards? Would most qualifying small refiners be able to meet the 30/80 standards within four years (six if a hardship extension is granted, which is dependent on the case made by the individual refiner), as proposed? The Panel report suggested that a period of six to ten years could

[50] In addition to gasoline produced from crude oil, a small refinery's baseline volume would include gasoline produced from purchased blendstocks where the blendstocks are substantially transformed using a refinery processing unit.

be desirable to provide sufficient time for small refiners to comply with the proposed standards. What are the arguments for granting more than four years of additional time and what are the environmental implications (and implications for Tier 2 vehicles) of such an extension?

- Should small refineries of multi-refinery companies (companies too large to meet the proposed small refiner criteria) be eligible for small refiner interim standards? Should refineries not producing gasoline as a major product (for example, refineries engaged primarily in the production of lubricants where gasoline is a small volume by-product) be eligible for small refiner interim standards regardless of corporate size/employment?
- If a small refiner operates more than one refinery (while still meeting our proposed small refiner criteria), should that refiner be permitted to aggregate the sulfur baselines and comply with the small refiner standards applicable to that aggregate baseline? Under the sulfur ABT program described below, we are proposing to require refiners to aggregate data from all of their refineries when determining compliance with the 2004 and 2005 corporate average standards (Table IV.C.–2) (but not the refinery gate standards, although we seek comment on that alternative).
- Rather than providing unique standards for qualifying small refiners, would the need for separate small refiner provisions be addressed if we were to adopt a regional sulfur program? In Section IV.C.1. above, we explained our concerns that a regional sulfur program would not achieve the same emission reductions we project for our Tier 2/gasoline sulfur program. However, some have suggested to us that a regional program would address the need for small refiner provisions since the majority of small refiners are thought to sell gasoline in the West. We know of several refiners that appear to meet our proposed criteria for being small that sell at least some of their gasoline production in the eastern U.S. (as defined by the oil industry's proposed program) and thus a regional program would not cover all small refiners. We encourage comments on this alternative, particularly from refiners who could be impacted by such a decision.
- Would a more general hardship provision that would be based on a showing of substantial economic hardship, such a discussed in Section IV.C.4.c., provide sufficient compliance flexibility to address the needs of small refiners?

4. Compliance Flexibilities

In addition to the basic standards applicable to refiners that were explained above, we are proposing two additional programs that will provide flexibility for refiners when complying with the proposed standards. The first is the sulfur ABT program mentioned previously. The second is a program to streamline the construction permitting process so that refiners can make the required process modifications by 2004.

a. *Sulfur Averaging, Banking, and Trading (ABT) Program*. We are proposing that any refiner or importer be allowed to generate, bank, and trade sulfur credits. A sulfur ABT program would accelerate the reduction of sulfur in gasoline and provide refiners with additional flexibility in achieving compliance with the 30 ppm standard in 2004 and beyond. The following paragraphs provide additional information about our proposed sulfur ABT program, to supplement that presented in Section IV.C.–3.a above. We encourage comments on the design elements we have proposed for the sulfur ABT program. If you believe alternative approaches would make the program more useful to the refining industry, please share your specific recommendations with us.

i. *Why Are We Proposing a Sulfur Averaging, Banking, and Trading Program?*

A sulfur ABT program, if properly implemented, would provide the opportunity for a win for both the refining industry and the environment. The flexibility provided by an ABT program could provide refiners more lead time to bring all of their refineries into compliance with the 30 ppm standard, by allowing them to use credits generated at one refinery to delay having to desulfurize gasoline from another refinery. ABT would provide the opportunity for reduced costs by allowing the industry the flexibility to average sulfur levels among different refineries, between companies, and across time. Since, under banking, early reductions have a value during program implementation, ABT provides an incentive for technological innovation and the early implementation of refining technology.

The ABT program could provide meaningful early benefits for the environment because it would allow the Tier 2 standards to be implemented earlier than might otherwise have been possible, and because it would provide direct environmental benefits. The first direct benefit relates to atmospheric sulfur loads. This benefit is largely independent of when credits are generated and used. However, atmospheric deposition and transformation rates of sulfur compounds tend to vary geographically and seasonally and thus we must consider whether a broad averaging program would have different pollutant effects when compared to a more constrained averaging program or a program without averaging. Any potential negative effects of a broad ABT program should be mitigated by the geographic distribution of refineries, the widespread distribution pipelines, and the fungible nature of gasoline. All of these factors, taken together, lead us to believe that any negative effect on atmospheric sulfur levels from ABT (relative to a single 30 ppm average/80 ppm cap in 2004) would be negligible. It should be noted that this situation is further moderated by the pool averages and caps proposed for 2004 and 2005, since these averages and caps would reduce actual gasoline sulfur levels as the ABT program phases in.

Another environmental benefit is related to the effect of gasoline sulfur on catalyst performance, as discussed in the draft RIA. Since catalyst performance depends in part on gasoline sulfur levels, we must consider whether the emissions benefits (measured in g/mi-per-ppm) of early sulfur reductions when credits are generated are essentially the same as the g/mi-per-ppm benefits when the credits are used. The effect of sulfur on emissions from Tier 0 and Tier 1 vehicles, which will dominate the fleet in 2000–2005, is approximately the same when sulfur levels increase from 30 to 150 ppm as it is when sulfur levels increase from 150 ppm to 330 ppm. In other words, for each ppm increase in sulfur levels, approximately the same effect on emissions results regardless of whether the increase is from low levels (e.g., from 30 ppm up to 150 ppm) or from higher levels (e.g., from 150 ppm up to current average levels). Therefore, the emissions benefits from credits generated before 2004 would essentially offset the emissions effects of those credits being used in 2004 and beyond, especially since corporate pool average sulfur levels could not exceed 120 ppm in 2004 and 90 ppm in 2005, and sulfur levels will be capped at 80 ppm in 2006 and beyond.

Nonetheless, there remains concern about the sensitivity of later models (NLEV and Tier 2) to sulfur and about the reversibility of the effect of higher sulfur levels on catalyst efficiency. More explicitly, the relatively few Tier 2 vehicles that would see somewhat higher sulfur levels than 30 ppm in 2004 and 2005 (about three-quarters of a model year of production) would not be able to fully recover the loss in emissions performance due to the higher sulfur levels. Hence, the corporate averages and caps would be necessary in these interim years. In 2006 and beyond, the 80 ppm cap and the 30 ppm average refinery standard, even with the ongoing use of credits to comply with the 30 ppm standard, would keep in-use sulfur levels very close to 30 ppm. Thus, Tier 2 vehicles sold in 2006 and beyond would receive appropriate protection from gasoline sulfur.

ABT programs must be designed and implemented carefully to be certain that they are sensitive to equity and competitive issues in the industry and do not create the potential for inadvertent emission increases. In the context of gasoline sulfur control, concerns about different baseline sulfur levels and different technological capabilities among refiners must be considered. Even with the proposed lead time, some refiners would find it easier to achieve reductions than would others. This is due to a number of factors, including refinery configuration, product mix (gasoline versus distillates), crude oil sulfur levels, and the ability to generate capital to fund the investment. At the same time the program must be designed to eliminate the possibility of windfall credits and to be sure that the environmental benefits associated with early sulfur reductions offset the potential forgone benefits when the credits are used.

The program we are proposing today attempts to strike a balance among all of these factors. Some of the elements and design features (such as the eligibility trigger and the baseline requirement) were included to address concerns such as timing, disparate capabilities among refineries, and the potential for excessive (''windfall'') credits. We are seeking comment on options for dealing with all of the issues we have identified.

The ABT program is voluntary. No refiner or importer qualifying for credits is required to generate them, use them, or make them available to others (except as discussed in Section IV.C.4.a.vi. below). The process for establishing a sulfur baseline and generating and using credits is outlined below.

ii. *How Would Refiners Establish a Sulfur Baseline?*

To establish a sulfur baseline against which credits would be calculated, we propose that by July 1, 2000, each refiner or importer that wants to generate credits submit two pieces of information to the Agency. One would be the volume-weighted average sulfur content for conventional gasoline (CG) for each refinery (or imported by that importer) for 1997 and 1998. The second would be the annual average volume of CG produced by that refinery (or imported by the importer) in those years. [51] [52]

Since we expect summer RFG sulfur levels to decrease in 2000 to approximately 150 ppm (due to the actions refiners will take to meet the Phase II NO_X standards for RFG), we are proposing to set the individual refinery sulfur baseline for summer RFG at 150 ppm, regardless of volume produced in 1997 and 1998. Winter RFG production would be assigned the same sulfur baseline as the refinery's conventional gasoline, without regard to the volume of winter RFG produced in 1997–98. Hence, no reporting of RFG sulfur levels or volumes would be required in setting a sulfur baseline. We encourage comments on the use of different sulfur baselines for summer and winter RFG, particularly regarding whether this could create a disincentive to produce RFG in the summer months. We do not want to jeopardize our RFG program, but at the same time, we want sulfur credits to reflect actions taken by refiners above and beyond their current operations and/or regulatory obligations.

Conventional gasoline produced in 2000 and beyond that exceeded 105% of the CG baseline volume produced at that refinery would be assigned a sulfur baseline (from which credits would be generated) of 150 ppm. This provision is intended to prevent increases in average sulfur levels resulting from increases in CG production. A refiner/importer of conventional gasoline to which oxygenate is added downstream during 1997–1998 could include the downstream oxygenate volume in that refinery's CG baseline, if the refiner can substantiate that oxygenate was added to that gasoline.

A refinery/importer that did not produce/import gasoline during 1997–1998 would be assigned a baseline of 150 ppm each for CG and RFG for the purposes of sulfur credit generation in 2000 and beyond. This provision would also apply to blenders of natural gasoline, butane, or similar non-oxygenated blending components. Such parties would be considered refiners and would need to meet all requirements, such as analyzing each batch of the blending component for sulfur prior to its addition to gasoline. Credits would be based only on the volume of the blending components. We encourage comments on alternative provisions for establishing baselines for refiners/importers that could not establish a 1997–98 sulfur baseline as described above. In particular would 150 ppm be appropriate, or would a greater or lesser sulfur content be most equitable and most environmentally neutral? Should this baseline be tied in some way to the trigger for credit generation in (as discussed below) 2000–2003?

We request comment on several aspects of this baseline provision. The 1997–1998 years for the baseline represent the latest available data and thus best reflects the present state of each refinery's gasoline sulfur levels. However, we already have established baseline sulfur levels for 1990 for most refineries. Except for changes related to RFG, average gasoline sulfur levels have changed little since 1990. Hence, we request comment on whether that 1990 baseline would be a suitable substitute. Alternately, we request comment on whether 1997 and 1998 are the appropriate years to average when establishing a sulfur baseline, given that mandatory use of the Complex Model starting in 1998 could have led to changes in sulfur levels between 1997 and 1998. Since our purpose in proposing to establish sulfur baselines is to try to capture current sulfur levels (within a reasonable date of the 2000 start date for credits to be generated), the sulfur baseline could be based on a single year's data (for example, 1998) rather than a two-year average. We proposed a two-year average to try to capture and accommodate operational fluctuations and changes. However, a single year's data may adequately capture current sulfur levels.

We are not proposing a formal baseline review and/or approval process since the proposal envisions a self-certifying process. Refiners would submit their 1997 and 1998 sulfur baseline data for each refinery to us, and then would generate credits from that baseline in 2000–2003. If we determined, through a refinery audit or other action, that the sulfur baseline was calculated with incorrect data, we would establish a new sulfur baseline and the refinery would subject to that baseline, even if it meant recalculating

[51] Since participation in the sulfur ABT program is voluntary, refines opting not to generate or use sulfur credits do not have to establish a sulfur baseline for this program.

[52] We believe that variations in specific gravity, which could affect the sulfur content of gasoline as determined on a mass basis, will average out over the year and need not be included in the calculations. However, we request comment on whether specific gravity should be considered in the calculation of sulfur baselines (including whether such data exists for 1997–98) and subsequently, in calculating credits generated relative to this baseline.

the number of credits generated in subsequent years. We have used this baseline review process in other mobile source programs and believe it works well, but we request comment this approach.

We considered the possibility that, since refiners report annual production information to EPA, we could issue baselines for each refinery rather than refiners having to submit them to us. However, we do not think this is a possible solution because many refiners comply with our RFG and CG requirements by aggregating the data from all of their refineries. Thus, the data we currently receive from refiners would not allow us to establish an individual baseline for every refinery in the U.S. (unless we went back to 1990 data). However, we would like comment on whether a more formal sulfur baseline approval process (say, a letter from the Agency or a date by which approval can be assumed unless the refiner hears otherwise) would be desirable. Keep in mind that even with a more formal baseline approval process, the baseline could be changed at a later date if we found, during an audit of refinery records, errors in compliance with the proposed baseline requirements. Hence, any up-front approval would only provide certainty that, based on the data reported to us, we believe the refiner had correctly applied the mathematical equations proposed today for establishing a sulfur baseline.

Some have raised the concern that if imported gasoline were allowed to be used for credit generation, as we propose today, foreign refiners might be able to gain an unfair advantage. For example, it is possible that foreign refiners could simply re-blend their gasoline (without installing new capital equipment) and send their lowest-sulfur refinery streams to the U.S. at a lower cost than gasoline produced by domestic refiners that had to reduce overall sulfur levels through desulfurization. Since importers, not foreign refiners, would be the parties assigned a sulfur baseline and eligible for generating credits, we do not believe foreign refiners would have a strong incentive to send lower sulfur gasolines to the U.S. We believe that the benefits of allowing importers to participate in the sulfur ABT program (more players in the credit trading field, more chance for early reductions in gasoline sulfur levels) outweigh the potential detriments. However, we encourage comment on the implications of the decision to allow imported gasoline to be used for credit generation.

Oxygenate blenders would not be able to participate in this proposed credit program because they would not be subject to the sulfur standard. Special provisions would exempt them from having to measure the sulfur content of the oxygenate they blend and from the recordkeeping and reporting requirements of the sulfur program, other than the requirements that apply to all parties that handle gasoline and gasoline blendstocks downstream of the refinery.

iii. *How Would Refiners Generate Credits?*

During the period 2000–2003, credits could be generated annually by any refinery that produced conventional gasoline averaging 150 ppm sulfur or less on an annual, volume-weighted basis. Credits would be calculated based on the amount of reduction from the refinery's CG sulfur baseline.[53] Credits could also be generated from winter RFG based on reductions from the sulfur baseline, if the winter RFG sulfur level averaged 150 ppm or less (on a seasonal volume-weighted basis). Similarly, summer RFG would need to have a seasonal volume-weighted average sulfur level below 150 ppm to be eligible for credit generation, although credits would only be created based on the difference between 150 ppm and the summer RFG sulfur average. Thus, credits would need to be generated separately for conventional gasoline and RFG. Conventional gasoline produced in excess of 105% of the baseline volume could only generate credits for sulfur reductions below 150 ppm, not for the cumulative reduction from the baseline sulfur level. Winter RFG would not be subject to any volume limitations, and thus refineries could generate credits for any volume of winter RFG that contains 150 ppm sulfur or less.

For example, if in 2002 a refinery reduced its annual average sulfur level for conventional gasoline from a baseline of 450 ppm to 150 ppm, its sulfur credits would be determined based on the difference in annual sulfur level (450–150=300 ppm) multiplied by the volume of conventional gasoline produced (up to 105% of the baseline CG volume). If this refinery produced more CG than 105% of the baseline volume, it would only generate credits from that incremental volume if the incremental gasoline were below 150 ppm. (For example, if the refinery's 2002 average CG sulfur level were 100 ppm, it would get 150–100=50 ppm sulfur credits on any volume in excess of 105% of its baseline CG volume, as well as 450–100=350 ppm for the baseline volume up to 105%.)

If this same refinery also produced RFG with an annual average sulfur content of 90 ppm in 2002, it could also receive sulfur credits calculated based on the difference between 150 ppm and 90 ppm (60 ppm) times the volume of summer RFG produced plus 360 ppm (450–90) times the volume of winter RFG produced. A refinery with a sulfur baseline lower than 150 ppm sulfur would only generate credits relative to reductions from its baseline, for either CG or winter RFG. Credits from summer RFG would be based on reductions from 150 ppm.

Several states have implemented or are considering gasoline sulfur control programs. To avoid double-counting of emission benefits, lower sulfur gasoline produced to comply with these state programs would not be eligible for early banking credits under this program.

In 2004 and beyond we propose that credits could only be generated for actual annual sulfur averages below the 30 ppm standard (combining conventional and reformulated gasolines), and only for the difference between the standard and the actual annual sulfur average. (For example, a refinery producing gasoline in 2004 that averaged 25 ppm could generate 30 − 25=5 ppm, while a refinery producing gasoline that averaged 40 ppm would not be eligible for any credits.)

We encourage comments on this credit generation concept. In particular, would these formulas permit sufficient credits to be generated industry-wide to provide adequate credits for use in compliance in 2004 and beyond? If not, what are the limitations on credits and what changes could be made to improve the likelihood that sufficient credits would be generated?

Our proposal to cap volumes on which credits could be generated at 105 percent of baseline levels is intended to preclude the possibility of closely-located refineries generating credits by moving blendstocks. This could occur if a refinery with a relatively low baseline level moved blendstocks to a refinery with relatively higher levels, thus allowing the somewhat artificial generation of credits. We request comment on whether such a provision is necessary and whether the 5 percent cap should be increased to as high as 10 percent to reasonably accommodate normal growth in volume. We raise some potential alternatives to these provisions in Section IC.C.4.a.vi. below, and encourage your consideration of all of these issues in your comments.

[53] If a refinery's baseline average were 150 ppm or less, credits could only be generated for annual average reduction's below the baseline level.

iv. *How Would Refiners Use Credits?*

Credits generated prior to 2004 would have to be used or transferred by 2007. Credits generated in 2004 and beyond would have to be used or transferred within five years of the year in which they were generated. If these credits were traded to another party, they would have to be used by the new owner within five years of the year of transfer. Since the transfer could occur any time within five years of generation, some credits could have a life of up to ten years.

Our proposed ABT program is designed to ease implementation of the new standards and credits would be of their greatest value during phase-in periods. ABT is not necessarily intended to permit a refinery to operate above the standard for a protracted time period. While limiting credit life might reduce the incentive to generate credits and could create a ''use or lose'' mentality, the credit program would seem to be of relatively small value to any refiner/importer that held credits for five years and did not need to use them. We believe that limiting credit life is appropriate since we must also consider the basic reason for ABT and address concerns about our ability and the ability of the refiners to maintain the integrity of the credit system over many years. EPA requests comment on credit life including options such as limiting life by depreciating their value over a period of years as well as longer or shorter periods of fixed credit value.

We propose that credits could be withdrawn from a refinery's/importer's credit bank or purchased from another refinery/importer to bring the annual sulfur average for each refinery down to the 30 ppm standard beginning in 2004. There would be no geographic constraints on credit trades. However, as explained in Section IV.C.3.a above, in 2004 no batch of domestically produced or imported gasoline could exceed 300 ppm, and a refinery's/importer's actual annual corporate pool average sulfur level could not exceed 120 ppm. (A refiner owning more than one refinery would have to aggregate the respective sulfur levels of gasoline produced at those refineries for determining compliance with the 120 ppm standard.) In 2005, gasoline sulfur would be capped at 180 ppm and the corporate pool average could not exceed 90 ppm. The aggregation requirement would also apply in 2005. As described above, credits would apply only to compliance with the 30 ppm refinery standard, not to the corporate pool average or the cap.

A refiner or importer choosing to participate in the ABT program would be required to file annual reports with the Agency indicating the applicable baselines or standard(s) in ppm sulfur, the annual average(s) in ppm sulfur, and the annual volume(s) in gallons (for each refinery). These calculations would be reported, along with an accounting of credits banked, transferred (sold), or acquired (bought). (For 2000–2003, the reports would only cover credits banked and traded.) The credits would be in units of ppm-gallons.

Thus, for each purchase of credits, as reported on the buyer's annual report, there should be a corresponding entry on the seller's annual report. Through the report, refiners would have to demonstrate that their average sulfur levels (with the use of credits, if necessary) comply with the 30 ppm standard at each refinery. Refiners would also have to demonstrate that the combined production from all refineries meets the corporate average standard. As mentioned above, the actual corporate averages could not exceed 120 ppm in 2004 and 90 ppm in 2005. The identity of refiners/refineries and importers involved in these transactions would be reported, along with the registration numbers assigned to them by the Agency under the RFG/CG program (40 CFR part 80, Subparts D, E, and F).

In addition, we are concerned that the potential exists for credits to be generated by one party and subsequently purchased or used in good faith by another, and later found to have been calculated or created improperly or otherwise determined to be invalid. In this case, both the seller and purchaser would have to adjust their sulfur calculations to reflect the proper credits and either party (or both) could be deemed in violation of the standards and other requirements if the adjusted calculations demonstrate noncompliance with an applicable standard. We have taken this approach in our other fuels enforcement programs. We welcome comments on this provision. In particular, we request comment on whether our program should be designed such that only the seller should be deemed in violation if that party sold invalid credits and, upon correction for this error, was found to have violated one or more standards. In general, mobile source ABT programs hold both parties liable.

For the duration of the credit program, each participating refinery and importer could make deposits to and withdrawals from its ''bank account''. All transactions would have to be concluded by the last day of February after the close of the annual compliance period (2004, 2005, etc.). It would be up to the industry to establish any mechanisms for linking buyers and sellers. The Agency does not intend to become involved in this marketplace activity.

We are also proposing to allow refiners to miss the 30 ppm standard for an individual refinery and to carry forward the credit debt that would have brought that refinery into compliance in the year the deficit occurred. This is very similar to provisions proposed today for auto manufacturers in complying with the averaging provisions Tier 2 standards. Under this provision, the refiner would have to make up the credit deficit and bring that refinery into compliance with the 30 ppm standard the next calendar year, or face penalties. This program would in no way absolve the refiner from having to meet the applicable per-gallon cap standard. This provision would provide some relief for refiners faced with an unexpected shutdown or that otherwise were unable to obtain sufficient credits to meet the 30 ppm standard. We welcome comment on this provision.

The following Table IV.C.–4 summarizes the compliance dates and program requirements of this proposed sulfur ABT program. See Section VI for more specific information, particularly about the dates that the sulfur caps would apply and the standards that would apply downstream of the refinery.

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Table IV.C.-4
Gasoline Sulfur Program Duration and Effective Dates

<table>
<tr><th>2000</th><th>2000 - 2003</th><th>2004</th><th>2005</th><th>2006</th><th>2007+</th></tr>
<tr><td rowspan="6">Application for Credit Program Baseline due by July 1</td><td>Early Credit Generation for Gasoline with ≤150 ppm Sulfur</td><td colspan="4"></td></tr>
<tr><td></td><td colspan="4">Credit Generation for ≤30 ppm Sulfur</td></tr>
<tr><td>Banking & Trading of Credits</td><td colspan="4">Banking & Trading of Credits</td></tr>
<tr><td></td><td colspan="2">Corporate Average Standards Apply</td><td colspan="2"></td></tr>
<tr><td rowspan="2"></td><td colspan="4">Compliance with 30 ppm Average Standard at the Refinery and Importer Level</td></tr>
<tr><td colspan="4">Phase-in of Downstream Cap Standards</td></tr>
</table>

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v. *Could Small Refiners Participate in the ABT Program?*

We believe that refiners complying under the small refiner provisions outlined in the previous section should not be permitted to use sulfur credits to meet the average standard applicable to their refineries. We are proposing to exclude small refiners from using credits to meet the small refiner standards because the small refiner standards are generally more lenient than the 30 ppm standard and thus these refiners should have less need for a credit trading program than the rest of the industry. Furthermore, small refiners, even those currently producing gasoline near the 30 ppm average, are given an additional two years (until 2008) to meet the 30 ppm standard compared to refiners complying under the sulfur ABT program. We want to ensure that the sulfur levels of the majority of gasoline are reduced on average, and overall, in 2004 and 2005; permitting small refiners to meet the more lenient standards through the purchase of credits could jeopardize that goal by resulting in in-use sulfur levels that are even greater than the maximum small refiner standard (300 ppm average). If a small refiner believed it could generate sufficient sulfur credits in 2000–2003, or obtain such credits through purchases from other refiners, to be able to meet the 30 ppm average and the corporate averages of 120 ppm in 2004 and 90 ppm in 2005, it should choose not to participate in the small refiner program and take full advantage of the sulfur ABT program.

However, small refiners would be permitted to generate and trade sulfur credits if they reduced sulfur levels early in 2000–2003, per the requirements outlined above. Furthermore, a small refiner could sell credits that were generated in 2000–2003 in 2004 and 2005 while at the same time meeting the small refinery standards. A small refiner wishing to generate and sell credits would have to establish the individual refinery sulfur baseline by the deadline specified above for the ABT program (July 1, 2000) but could wait until June 1, 2002 to apply for small refiner status. However, the standards assigned to that refinery (as presented in Table IV.C–3) would be based on the sulfur level from which credits were generated, not the 1997–98 baseline sulfur level, since the refiner would have already demonstrated the ability to meet the lower sulfur level (in this case, 150 ppm or lower on an annual average basis).

At any time, a small refiner could ‘‘opt out’’ of the small refiner program and, beginning the next calendar year, comply with the standards in Table IV.C–2. The refiner would have to notify us of this change in compliance program. Once a small refiner left the small refiner program, however, we propose that it would not be eligible to re-enter the small refiner program. We encourage comments on this provision.

The sulfur ABT program could provide an alternative to offering any small refiner standards, if small refiners were capable of complying with the proposed pool average standards and caps in 2004 and 2005 just as larger refiners could. In this case, all refiners, large or small, could obtain credits necessary to meet the 30 ppm average standard for the two intervening years. However, EPA recognizes that this may not be the best response to the needs of small refiners, and has proposed, as a result of the SBREFA Panel process, alternate standards in section IV.C.3.b of this document. Indeed many small refiners expressed concern during the Panel process that an ABT program would not address their needs. However, we welcome comments on the pros and cons of using the sulfur ABT program to provide regulatory relief for small refiners in lieu of additional regulatory standards unique to small refiners.

vi. *What Alternative Implementation Approaches Are Possible?*

As we were developing this proposal, members of the oil industry and others expressed concern that the ABT program as described above may not be of great value in providing flexibility in complying with the 30 ppm standard in 2004. Several different concerns have been expressed.

Industry representatives have asserted that the opportunity to generate early credits is limited because the proposed lead time would be too short to implement enough of the refinery operational changes and capital investments needed to achieve sulfur reductions before 2004. Additionally, the industry is concerned that relying on early credits generated with what is perhaps the best long-term technology(ies) is problematic because the preferred technology(ies) is new and does not yet have a proven performance record. Their concern is further exacerbated by the uncertainty in the diesel fuel sulfur picture, the MTBE /oxygenates situation developing in California, and the DI petition discussed below, as well as ongoing state initiatives to reduce sulfur in gasoline before this action is decided upon.

When credits are generated, there is a fear that those that generate them will hoard them, particularly refiners that operate several refineries. And when credits are made available for trade, they may not become publicly available in enough time for them to be considered by others in their capital investment planning, so essentially all refineries would have to take steps to implement 30 ppm technology by 2004. These issues may be of special concern to those moderate sized refiners that are too large to qualify as small entities but do not have enough refineries or refineries of the right gasoline production volume to internally optimize their operations under the ABT program.

Given these uncertainties about credit availability, the refiners may need additional flexibility as a means to provide relief to those that make a good faith effort to comply but are precluded by circumstances beyond their control. These may include unanticipated technological and commercial concerns, credit availability problems, or *force majeure* type events.

We have examined this issue of credit availability and our analysis, which is presented in the Draft RIA, indicates that credits should be available by 2004 for the 2004/5 phase-in. This is based on the fact that the 300 ppm cap in 2004 would require that all refineries with a baseline above 300 ppm reduce sulfur by 2004. And, while they could choose to just achieve 300 ppm, some would need greater reductions to comply with the 120 ppm corporate pool average standard and all would be facing increasingly more stringent requirements in 2005 and beyond. Quite simply, we believe that good business sense would dictate that once a hardware investment is made the refinery would shoot for 30 ppm or less. As the analysis shows, this approach implemented over just three years would yield compliance with the 120 ppm corporate pool average and would generate ample credits. We requested comment on our analysis in the Draft RIA and the underlying analytical approach.

EPA is proposing the ABT program described above in order to increase the refiners'/importers' confidence that they could comply in 2004. And, while our analysis indicates that credits would be available for 2004/2005 compliance, we realize that the ABT program might not meet its objective if the industry did not have confidence that credits would be available in enough time and in sufficient quantities to enable them to make economically efficient investment decisions. It is our desire to provide the industry as much flexibility as possible to ease implementation and phase-in while still meeting the objectives of the program as described above. Toward that end we are asking for comment on several variations on the above proposal that might increase its overall value as a means to provide flexibility in meeting the proposed standards. These can be divided into four categories: (1) Modifications to the design elements of the proposed ABT program, (2) a compliance supplement pool, (3) an allowance-based system, and (4) reserved credits. As constructed below, the compliance supplement pool, an allowance-based system, and reserved credits could be implemented in varying ways to complement the early ABT program. EPA asks comments on the cost and air quality impact implications of these concepts, which are described in more detail below.

Potential Modifications to Proposed ABT Program

Modifications to the base program to increase the potential availability of credits and the time over which these credits could be used might increase the effectiveness of the proposed ABT program. These changes could potentially affect both the near-term when the program was phasing-in and the long term when the 30 ppm standard was fully implemented.

The 150 ppm trigger value is designed to ''level the playing field'' between companies with relatively low baselines and those with relatively high baselines. Those with high baselines could potentially generate more credits than those with lower baselines, but at a somewhat greater cost since achieving 150 ppm or less becomes increasing more difficult with higher sulfur gasoline. Those with baselines closer to 150 ppm may be able to generate fewer credits, but generate them more easily.

However, requiring that gasoline be below 150 ppm before credits could be generated might preclude credit generation from higher sulfur gasolines that could achieve large, real reductions in sulfur. The size of the potential credit pool could be increased, perhaps dramatically, if the trigger were relaxed or eliminated. We would like comment on trigger values higher than 150 ppm for CG and winter RFG. We would also request comment on expressing the trigger as a percent reduction from baseline levels (e.g., 10–25%) rather than as an absolute value. In addition, we request comment on a hybrid concept under which credits would be generated for CG and winter RFG depending on initial 1997/1998 baseline sulfur levels (gasoline less than 150 ppm sulfur would qualify, gasoline between 150 ppm and 350 ppm sulfur would need a 10–15 percent reduction, and gasoline greater than 350 ppm sulfur would need a 15–20 percent reduction to qualify.) It would be helpful for those suggesting the ''no-trigger'' approach to also address the issue of equity among refiners with different baselines.

In combination with comments on the trigger, we also ask for comment on the proposed phase-in approach. The 300 ppm cap effective October 1, 2003 and the timing for the 30 ppm average standard would both be important factors affecting the transition to low-sulfur gasoline. Our analysis of the potential availability of credits (discussed above and presented in the Draft RIA) indicates that most of the credits needed to smooth out the transition would be generated by low-sulfur winter RFG. Our analysis also assumes that a substantial number of credits would be generated by refiners investing in technology capable of producing 30 ppm gasoline prior to 2004 to ensure compliance with the 300 ppm cap. If refiners take another approach to meeting the 300 ppm cap (i.e., one that does not result in significant credit generation), fewer excess credits would be available. However, as long as some refiners invest in 30 ppm technology before 2004, we believe sufficient credits would be available. We encourage comment on our proposed phase-in approach.

Specifically, should the interim phase-in program be extended by an additional year to provide an even smoother transition to the 30 ppm standard (e.g., 120/300, 105/210, 90/180 for 2004, 2005, and 2006)? Should the time frame for the 30 ppm average standard be shifted to 2005, for example, while retaining the 120/300 ppm caps for 2004, to provide more time for transition to the 30 ppm standard? Should credits expire after 2007 (as proposed) or would a shorter (or longer) credit life be appropriate?

We are also seeking comment on a concept that would provide an incentive to introduce clean technology early. Under this concept, any sulfur credits generated before 2004 would be banked at a rate of 1.5 to 2.0 times the amount generated, if the annual average for that refinery were equal to or less than 30 ppm and if the credits resulted from the implementation of gasoline sulfur reduction technology (hardware) not previously used at that refinery. This multiplier would not be available for credits generated from modest operational changes or product separation at the refinery or downstream. Calculation of the un-multiplied credits would be at the refinery level. Neither domestic refiners nor importers could qualify by segregating product or product streams either from their refinery(ies) or in the case of importers from one or more offshore refineries. Also, while refiners/importers could get sulfur credits under ABT through the use of allowable oxygenates, these could not be used as part of the basis for achieving the 30 ppm average. EPA seeks comment on the need for and utility of such an approach and on whether it is appropriate to encourage implementation of sulfur control technology in this manner.

Compliance Supplement Pool

To address concerns about credit supply and the timeliness of the availability of credits, and as a way of providing additional flexibility, particularly to refiners that encounter unexpected problems in complying, we are considering the concept of a government-created and -operated compliance supplement pool for the sulfur ABT program. Under this concept, the government would create a pool of additional credits that could be provided to refiners/importers. This pool would build refiner confidence that a supply of credits would be available in the market and that credits could in fact be considered as part of the business plan for 2004–2005 compliance. Credits from this pool could first be made available in the 2000–2001 time frame and perhaps in subsequent years and could only be used in 2004–2005. This program would supplement the 2000–2003 early credit approach under ABT.

There are a number of issues related to implementing such a program. The size of the pool potentially available for use in 2004 and 2005 would be a critical issue. A larger pool would lower the chance that a refiner/importer could not get credits, but would reduce the environmental benefits of the overall program. Clear rules on the availability of credits would need to be established at the outset so that refiners/importers could make correct investment decisions. In addition, EPA would not want a compliance supplement pool to supplant the need for each refiner to make aggressive efforts to comply in the appropriate time or for a pool to create a disincentive for refiners to generate early credits. If credits from early reductions were available at a reasonable price, EPA would prefer that refiners/importers purchase such credits rather than looking to a compliance supplement pool. EPA seeks comment on the appropriate size of a compliance supplement pool in light of these factors.

The conditions under which a refiner/importer would be eligible for credits are important. For example, the pool could be made available only to refiners that had demonstrated that they had made a good faith effort to comply with the 2004 requirements, but, due to circumstances beyond their control could not do so. Providing credits to a refiner that failed to make good faith efforts to procure and install the technology would create the wrong incentives and could be unfair to competitors that had invested resources to comply.

Options for distributing credits in the pool might include granting credits as rewards to those that generated some early reductions, distribution based primarily or solely on need, equal distribution to all, pro-rata distribution based on volume, making credits available at a fixed price, or a credit auction. These approaches could be considered singly or in combination. For example, the majority of the compliance supplement pool could be distributed based on need, with due consideration of the effect of lack of credits on gasoline supply in a given area. In this case, the remaining portion might be set aside and auctioned off to provide a price signal and a certain source of credits.

It would seem that any such compliance pool should be administered by the government or its agent, but decisions on credit applications would include a public process. As part of our deliberations on this concept we need to decide whether credits could be used to meet the interim corporate pool averages (120/90 ppm) or just the 30 ppm standard or both. Unlike credits generated by refiners/importers reducing actual sulfur levels, any credits under this program would expire after 2005.

Credits from the compliance supplement pool would be government-created and not derived from actual reductions in gasoline sulfur. If credits from the compliance supplement pool were distributed at little or no cost to the receiver, such an approach might create an inequity between those using credits and those who invested in technology to reduce sulfur. As a means to address the potential environmental effects of these government credits and to correct financial inequities among refiners/importers, we seek comment on a provision that would require those awarded these credits from the compliance supplement pool to repay them. The credits to be used for repayment could be generated internally in 2004–2006, purchased surplus credits from other refiners/importers, or simply unused credits originally distributed from the compliance supplement pool. These credits would have to be repaid by the expiration of the period to close credit balances under the interim program (2006, taking into account the one-year credit debt carry-forward provision).

If, as mentioned above, credits were sold at a fixed price or auction, several issues would arise. Should payment be through monetary means? If so, what is EPA's authority to engage in such monetary transactions, and what would be done with any proceeds? There is also an issue with regard to a requirement to both buy credits for cash and then also repay with credits. Alternatively, credits could be allocated based on a determination that a refiner/importer needs the credits, in conjunction with a determination regarding the refiner's/importer's ability and willingness to repay the credits to the pool in the future at a rate greater than 1:1. A credit auction could be held in a similar way, that being the willingness of the bidder to repay the credits in the future at a rate greater than 1:1. In these approaches, a refiner/importer seeking credits might be willing to repay them at a rate of say 1.2:1, thus essentially offering or bidding a 20 percent premium. This could be done as a one-time premium or perhaps as a discount at the time the credits are issued from the pools. Under this system no money exchange would be required. This would simplify set-up of the compliance supplement pool, allow refiners to conserve capital for purposes of capital investment, and create an environmental return for the compliance supplement pool. In addition, it would result in credits being provided to refiners/importers that need them, and that are expected to achieve additional environmental benefits in the future by generating or purchasing excess credits.

The ''reasonableness'' of the price of credits is critical to any approach requiring repayment from those entities using these credits. We request comment and suggestions on ways to establish reasonable credit prices. For example, as an upper bound, EPA might set a credit price based on information received during the rulemaking on the cost of sulfur removal for different technologies.

EPA also seeks comment on whether refiners/importers that used credits from the compliance supplement pool should be excused from the repayment of some or all of the credits if they could demonstrate that it was not feasible for them to generate credits themselves and insufficient credits were available at a reasonable price. Finally, EPA seeks comment on how to ensure that refiners/importers that used credits from the compliance supplement pool would in fact repay those credits. One option would be to hold such refiners/ importers liable for failure to meet the sulfur standards over the averaging period during which they relied on credits from the compliance supplement pool, if such credits were not repaid in time. EPA seeks comment on this option, as well as other alternatives that would ensure that compliance supplement pool credits were repaid.

EPA has some experience with the compliance supplement pool approach as part of the NO_X SIP Call (ROTR) discussed in Section III above. In this process, a compliance supplement pool was created to address concerns raised by industry about how the requirements might affect the reliability of the supply of electric power. The size of the NO_X compliance supplement pool was created based on an EPA projection of what compliance shortfalls might result if problems developed in implementing the control technology. The NO_X SIP Call pool may be allocated through direct distribution based on need or as a reward for early reductions.

Allowance-Based System

In the context of gasoline sulfur, a traditional allowance program would provide more confidence in the availability of ''credits'' (surplus allowances) by creating sulfur budgets that the industry (refiners and importers) would be required to meet during the 2004–5 phase-in and perhaps beyond. This budget would be created on a mass basis using gasoline volume and the applicable regulatory standard. This budget would then have to be allocated to individual refiners and importers. If an individual refinery or importer had sulfur levels below its allocation this would create surplus allowances that could be traded. Allowances for 2004 and later would be made available in 2001. This would facilitate the development of a market in allowances, since those planning to beat the requirements for 2004/5 could market their allowances early. This could significantly contribute to the certainty that surplus allowances would be available in time for consideration by others in their 2004 business planning.

While there are other possibilities, it would seem reasonable to allocate the budgets to individual refiners/importers in the 2004 and later time period based upon their individual percentages of the gasoline market. To be consistent with other aspects of this proposal this could be done at the corporate level in 2004/ 5 and at the individual refinery/ importer level in 2006 and later.

One major benefit of such an approach is that refiners/importers could trade part or all of their 2004 and later allowances for future use without EPA involvement and those purchasing these allowances could do so early enough to allow a more orderly and reasoned set of capital investment decisions. Also, since it would be allowances, not credits, that would be traded, the seller could be held solely responsible for failure to meet its budget without involving the buyer. The trading of allowances would be relatively unencumbered. Allowances could be used to meet the budgets allocated under the regulatory standard.

This approach would provide increased flexibility and certainty, it is not clear that a large number of surplus allowances would be created, since surplus allowances would only exist relative to a budget based on the 30 ppm standard. Obviously the number of allowances created in 2004 and 2005 could be increased if the budget were based on a value higher than the 30 ppm regulatory standard, but this would require a fundamental change in overall program design. Alternatively, the number of surplus allowances might be increased if the allowances program were started earlier. For example, refiners/importers could be allocated budgets beginning in 2001 based on the product of their 1997/1998 sulfur baselines in ppm (with appropriate adjustments for RFG Phase II) and their gasoline volume. Any reductions in the average sulfur levels or volume from the baseline level during that 2001–2003 time period would result in surplus allowances.

While the idea of pre-2004 allowances has merit, it requires the *de facto* implementation of a standard before 2004 (since each refiner's/importer's budget would in effect be a standard), in order to establish allowances. And, in contrast to the ABT program where participation is voluntary and no requirements exist before 2004, an allowance system would require refiners subject to the allowance program to hold sufficient allowances to cover their calculated mass emissions starting in 2001.

In principle, an allowance system could be designed to incorporate all of the features of an ABT credit system as described above. We are interested in comment on the viability of such an allowance program as an alternative to the traditional ABT program and whether such a program would have to be mandatory for all refiners/importers in order to be effective. For example, could we structure an allowance program such that the refiner opts into if it intends to generate or use allowances or opts out of if it does not? We are also interested in comment on the parameters of such a program, including the appropriate budget levels, methods for distributing the budgets to refiners/importers, and whether allowances could be used to meet the corporate pool averages, the regulatory standard, or both. As with the ABT program, we would like to hear your views on the years over which such a program should apply (e.g., should it start in 2001?, should it extend beyond 2005?), as well as the other regulatory requirements that should apply in each year.

We also request comment on whether the allowance program could be established as a supplement to the credit program. If an allowance program is implemented along with a compliance supplement pool and/or early ABT we are interested in comments on how to make credits fully exchangeable among the programs. We are also interested in comments on how the programs could/should be integrated. For example, could we let a refiner/importer generate early ABT credits and at the same time sell 2004–2005 allowances?

Reserved Credits

EPA is also aware of concerns regarding whether refiners that earned or received credits would make them available in a timely manner to those that needed them, particularly to small- to mid-sized refiners/importers. If an adequate number of credits were not available in a timely manner and for a reasonable price, small- to mid-size refiners would have no choice but to pursue near term capital investment to comply in 2004. This might be the appropriate course for many of these refineries, but we do not think it is appropriate for them to be precluded from the same flexibility as larger refineries.

We are seeking comment on whether we should require that a set percentage (e.g., 1015%) of all credits generated in early ABT (2000–2003), awarded through the compliance supplement pool, or earned through the allowance-based approach either must be retired or offered for trade outside of the refining company that originally generated or was granted them. Under such a provision, refiners/importers would be required to set aside a percentage of credits/allowances they generate, but could choose whether to retire them or offer them for sale at a fair market price to another refiner/importer. Regardless of which option the refiner/importer chose, the results would be beneficial—the environment would benefit if credits are retired, and credit availability would improve if the refiner chose to sell credits. We are also interested in your views as to how this objective might be accomplished.

EPA also asks comment on the disposition of credits that were put up for trade one or more times during the period 2004–2006 but did not sell during that period. This could be the case if a credit owner offered credits for sale at a price in excess of fair market value and thus they were not purchased by another party or if credit supply significantly exceed demand. In this kind of situation, should the credits be retired or revert to the generator at a full or reduced rate (e.g., 50%) for future use in compliance determinations? We request comment on whether such a provision for reserved credits would be needed by small- to mid-sized refiners and whether the reservation of 10–15 percent of credits would be sufficient to address the concerns. We also seek comment on whether such a pool should be supplemented by the government through an auction to ensure that the pool size is adequate and whether such a pool could be useful in helping to establish a market price for company owned credits.

b. *Refinery Air Pollution Permitting Requirements.* As discussed previously in this document, this proposed program would result in significant emission reductions from reducing sulfur in gasoline nationally, through the emission reductions from the current fleet of vehicles and ensuring the efficacy of new technologies in future vehicles. In order to achieve this environmental benefit as soon as possible, we want to be sure the public is aware of the full range of available methods for expediting permits required for refinery process changes to reduce gasoline sulfur. Expedited permitting also will facilitate refiners' ability to generate sulfur credits, under today's proposed sulfur Averaging, Banking and Trading program, described in the previous section.

There are two key Clean Air Act permitting programs that refiners must comply with when making changes at their existing facilities to implement gasoline sulfur control—the New Source Review (NSR) program and the Title V operating permit program. Typically, both of these programs are administered by state/local permitting agencies, with EPA oversight. While the basic requirements of these programs are dictated by the Clean Air Act and EPA regulations, the specific requirements of each state/local permitting program may vary.

We recognize that compliance with these air permitting requirements is an integral component in any plan to implement the gasoline sulfur control program under the schedule proposed today. To help refiners meet the permit requirements, below we discuss the possible mechanisms to address the substantive requirements of the major NSR and Title V programs, including possible opportunities to streamline and expedite the processing of permit applications. Finally, we conclude this section by discussing possible tools that we are currently testing in the experimental Pollution Prevention in Permitting Program (P4), which promotes permit streamlining and flexibility for Title V operating permits, along with increased pollution prevention activities. We encourage commenters to provide suggestions for additional opportunities to streamline the permitting process to accommodate the implementation of the proposed gasoline desulfurization requirements for the refining industry sector.

The American Petroleum Institute (API) has sent a letter to EPA outlining its concerns about the potential impact of various permitting requirements on the industry's ability to meet future gasoline sulfur standards, as well as their suggested options for permit streamlining.[54] This letter is included in the docket for this rulemaking. We are aware that individual refineries are in different situations regarding the modification to current operation that would be needed to meet the proposed sulfur standard and the regulatory requirements applicable to those modifications. Based on the limited information available at present, some refineries may not increase emissions significantly, and others may find it most economical to make on-site emission reductions at the plant to avoid emission increases. Accordingly, we request comment on the extent to which the various mechanisms to streamline the permitting process discussed in this section are in fact needed or useful. We request that commenters supporting such streamlining describe the specific refiner situations in which they believe streamlining is needed, and encourage them to provide any suggestions for additional opportunities to streamline the permit process to expedite refineries' preparation to meet the proposed sulfur standards.

i. *New Source Review Program.*

The New Source Review (NSR) program,[55] as it applies to existing major sources of air pollution, requires that a preconstruction permit be issued before a source begins construction of any project that would result in a significant net emissions increase. With respect to NSR, we anticipate that refineries will fall into one of two categories if the proposed sulfur standards are implemented. The first category consists of those refineries that would be able to avoid major NSR by demonstrating that the physical and operational changes needed to reduce gasoline sulfur do not result in a net emission increase of the quantity that would require a major NSR permit. Major NSR would not apply where: (1) The proposed changes would not result in an emissions increase at the refinery; (2) the increase is, in and of itself, less than ''significant''[56]; or (3) the refinery ''nets'' the project out of review. In most cases, even where a refinery change to accommodate the production of lower sulfur gasoline does not trigger the major source NSR program, the project still will be subject to a state's general, or ''minor,'' NSR program.[57] The second category consists of those refineries that would experience a significant net emissions increase as a result of process changes necessary to accommodate gasoline sulfur control and, therefore, will trigger major NSR applicability and the attendant permit process (e.g., nonattainment NSR or Prevention of Significant Deterioration). Accordingly, such facilities must obtain a major source preconstruction permit prior to making these process changes.

As described previously in today's document, there are several types of process changes refineries could make to meet the proposed gasoline sulfur

[54] Letter from William F. O'Keefe, Executive Vice President, American Petroleum Institute, to Bruce Jordan, U.S. EPA, Office of Air Quality Planning and Standards, dated February 12, 1999 (Docket item IIG–304).

[55] See 40 CFR 51.165, 40 CFR 51.166, 40 CFR 52.21, 42 U.S.C. 7475, and 42 U.S.C. 7503.

[56] EPA's and state/local regulations for major NSR define ''significance'' levels for various pollutants.

[57] This permitting program applies to the construction or modification of any stationary source. See 40 CFR 51.160 and 42 U.S.C. 7410(a)(2)(C).

levels. Traditional sulfur removal technologies include installing a hydrocracker upstream, or a hydrotreater upstream or downstream, of the fluidized catalytic cracker (FCC) unit, the unit that produces the largest fraction of gasoline. There also are improved desulfurization technologies, CDHydro and CDHDS (licensed by the company CDTECH) and OCTGAIN 220 (licensed by Mobil Oil). These technologies use conventional refining processes combined in new ways, with either improved catalysts or other design changes to maximize gasoline desulfurization effectiveness with minimal negative effects, such as octane loss. To different degrees, all these technologies involve the use of a furnace and, thus, have the potential to increase pollutants associated with combustion, such as NO_X, VOCs, PM, CO, and SO_2. The addition of these technologies also could result in equipment leaks of petroleum compounds, which could increase emissions of VOCs and other pollutants. It also is possible that the increased removal of sulfur from the gasoline stream might require increased capacity of a number of refinery processes, such as the sulfur recovery unit (SRU), which converts hydrogen sulfide into elemental sulfur and is associated with SO_2 emissions. The emission increase associated with a desulfurization project will vary from refinery to refinery, depending on a number of source-specific factors, such as the specific refinery configuration, choice of desulfurization technology, amount of gasoline production, and type of fuel used to fire the furnace.

While we do not have sufficient information at this time to estimate the number of refineries nationwide that will trigger major NSR, we believe it could be substantial, given that over 100 refineries in the country would be required to make desulfurization process changes under today's proposal. Estimates from one vendor indicate that its desulfurization process could result in emission increases that are considered ''significant'' in severe ozone nonattainment areas (i.e., greater than 25 tons/year of NO_X and VOC), which would trigger major source nonattainment NSR review. Since the significance threshold generally is lower in certain nonattainment areas (i.e., those nonattainment areas classified as serious and above for ozone), refineries located in those nonattainment areas may be the most likely to trigger major NSR review. There are many refineries located in ozone nonattainment areas (e.g., parts of the Gulf Coast).

NSR Applicability Principles

A refiner's ability to avoid triggering major NSR by keeping emission increases below the major NSR applicability cutoffs will depend primarily on the case-by-case circumstances of each refinery. Nevertheless, numerous means by which a source can otherwise legally avoid major NSR permitting are available to all refineries for consideration and possible use. In addition, as discussed below, the Agency is prepared to work with refineries to explore the use of certain NSR applicability mechanisms (i.e., plant wide applicability limits or ''PALs''), where appropriate.

To the extent needed, we intend to work with state/local permitting authorities to provide assistance with the proper application of the NSR rules on an expedited basis for permits involving refinery desulfurization projects. We want to ensure that applicability decisions are made at the earliest possible opportunity and consider the full spectrum of options available so that a refiner can adjust, or possibly reconfigure, planned desulfurization projects so as to prevent significant emission increases and thereby avoid major NSR within the framework of the current regulations. In addition, timely applicability decisions will provide added certainty as to the applicable NSR requirements and, where a major NSR permit is needed, how to best to expedite the issuance of a permit.

Depending on the nature of the physical or operational changes necessary to accommodate desulfurization projects, the NSR applicability process for major modifications can be a complex and time consuming exercise. The NSR regulatory provisions require that a proposed physical change result in a significant net emissions increase in order for the change to be considered a modification and therefore subject to NSR. We expect that there likely will be questions regarding which, and how, existing emission units are affected by the change, including how to calculate the magnitude of the emissions change for major NSR applicability purposes. We are committed to working with refiners and state/local air pollution control agencies to clarify and ensure that, in applicability analyses for gasoline desulfurization projects, only those emissions increases resulting from the physical or operational changes necessary to comply with gasoline desulfurization requirements are included in the applicability analysis.

In doing an applicability analysis for major NSR, refineries should analyze their past, current, and future operations and emissions to determine whether it is possible to avoid major NSR based upon their facility-specific circumstances, including the use of previous emission reductions at the facility to ''net'' out of NSR. Similarly, sources might avoid NSR by using Plantwide Applicability Limits (PALs) to cap emissions. Emissions netting is a term that refers to the process of considering certain previous and prospective emission changes at an existing major source to determine if a net emissions increase will result from the proposed new project. Where the sum total of creditable increases and decreases across the refinery is less than significant, major NSR would not apply. In addition, if the proposed emissions increase from a proposed project (in this case, a project undertaken to reduce gasoline sulfur levels) is by itself, without considering any decreases, less than significant, major NSR would also not apply.

PALs may provide another opportunity for refineries to avoid triggering major NSR applicability. The voluntary, source-specific PAL is a straightforward, flexible approach to determine whether changes at an existing major source of air pollution result in a significant net emissions increase. By restricting (or ''capping'') a facility's emissions to a level representative of current actual emissions, a PAL allows a source to change operations and equipment without having to undergo major NSR permitting. For example, as long as refinery activities do not result in emissions above the PAL cap level, the refinery would not be subject to major NSR, regardless of the nature of the activity. Under a PAL, instead of a case-by-case assessment of whether a proposed change is subject to or excluded from major NSR, the refinery manager knows that as long as the refinery stays within its emissions cap, major NSR will not be triggered. Production units may be started and stopped, production lines reconfigured, and products changed and revamped without delay from major NSR permitting.

Because of these advantages, the Agency previously has proposed to incorporate PALs in all of its NSR regulations (see 61 FR 38250, 38264, July 23, 1996), and has worked with state permitting authorities to develop PALs for individual sources. Likewise, the Agency is committed to exploring the propriety of authorizing PALs for refineries subject to the final gasoline sulfur control rules. We are examining our authorities to assure they support these approaches. Should it be necessary, EPA stands prepared to issue final regulations to make PALs available to sources making changes to comply with these gasoline sulfur control requirements.

We are further committed to investigating with affected refineries whether a PAL might be a valuable tool for managing a number of other Clean Air Act requirements. For instance, depending on the relevant state rules, a PAL also could include terms that allow facility changes to be made without triggering minor NSR. It is our experience that, in the cases where PALs have been applied, both industry and air pollution regulators have benefitted from the regulatory certainty and simplicity a PAL provides. The use of a PAL can enhance a refinery's ability to make appropriately designated changes quickly, without having to evaluate a baseline for each modification, determine the contemporaneous increases and decreases, and engage in other time-consuming netting procedures required under the major NSR program on a case-by-case basis. A PAL also can encourage a source to reduce emissions voluntarily (e.g., from pollution prevention or other emission reduction efforts), so that it has sufficient room for growth (under the PAL) to accommodate increased emissions from future process changes.

Approaches to Expedite the Processing of NSR Permit Applications

Notwithstanding the availability of the major NSR applicability principles and mechanisms discussed above, we anticipate that it will not be possible for all refineries subject to the gasoline desulfurization requirements to prevent significant emission increases and avoid major NSR. Additionally, even those facilities that are able to avoid major NSR likely will be required to obtain a state minor NSR permit. For facilities subject to major NSR, the timing of permit issuance could vary depending on many factors, including the complexity of process changes, the type of permit required, air quality impact, control technology reviews, and the state's overall permit workload. It is not uncommon for issuance of a major source preconstruction permit to take six to 12 months from the receipt of a source's complete permit application. In addition, determining the applicable permitting requirements for refineries is often complex, due to the wide array of emission points and processes.

To help expedite the NSR permitting process, we suggest the following streamlining approaches. Since state/local governments typically are the lead permitting agencies, we will work closely with them on any of these efforts. We solicit comments on the efficacy of these approaches and opportunities for additional streamlining. We are particularly interested in understanding whether these permit streamlining approaches could enable refineries to begin voluntarily producing lower-sulfur gasoline earlier than the compliance dates proposed today, so that the environmental benefits may be realized sooner than 2004 and ABT credits (see previous Section) could be generated.

• *Federal guidance on streamlining certain major NSR permitting requirements, such as control technology and compliance parameters.* Although the major NSR permit is a case- and source-specific evaluation, we could provide guidance on certain aspects of refinery projects designed to reduce fuel sulfur that share a common requirement or circumstance. For example, for refinery projects permitted in the same time frame, the Lowest Achievable Emission Rate (LAER) requirement should be the same for identical emissions units regardless of the location of the individual refinery. In this case, we could define for the industry what emissions levels would be expected to meet LAER and provide model permit conditions, including appropriate monitoring, record keeping, and reporting. Although Best Available Control Technology (BACT) determinations require case-by-case considerations, we also could issue guidance setting out a level of emissions that, in our view, satisfies BACT for the class or category of emission units associated with refinery desulfurization. We expect that providing BACT and LAER guidance would help to expedite major source permitting and add more certainty to the permit process. Consequently, for any applications processed within a discrete time frame, a presumptive federal LAER and/or BACT could be established.

• *Availability of offsets.* The major NSR permitting provisions require that a significant emissions increase of nonattainment pollutants must be offset by emission reductions from other sources. We solicit comment on the need for offsets by refineries making modifications to meet the proposed sulfur standards, and the expected size or volume of any offsets that may be necessary. In addition, to the extent offsets may be useful or necessary, EPA requests comment on whether on-site emissions reductions at the refinery could be used to avoid the expected emissions increases that would otherwise occur. We will work with refiners and state/local air pollution control agencies to explore options and possible new approaches that would help ensure the availability of offsets. For example, it may be possible to establish pre-funded offset pools, designed specifically for offsetting emissions increases resulting from gasoline desulfurization projects. We believe that the establishment of preapproved offset banks or pools could greatly expedite permitting in nonattainment areas.

To help give certainty that offsets will be available, we seek comment on how and whether emission reductions resulting from vehicles operated on low sulfur gasoline could be used as offsets by refineries implementing gasoline sulfur controls. For example, it may be possible for a state, within a given nonattainment area, to set aside a portion of the emission reductions expected from vehicles operating on low sulfur gasoline and dedicate those reductions for use as offsets by refineries. These offsets would have to meet all the criteria currently established for being creditable, and could not be ''double-counted'' by the state for other SIP planning purposes. We request comment on the ability of emission reductions from the use of low sulfur gasoline to meet the Clean Air Act's criteria for creditable offsets for NSR purposes. Since securing offsets can be a significant challenge to sources undergoing major NSR permitting in nonattainment areas, we believe this approach could substantially speed up, and add certainty to, the permitting process. We believe this approach is worth evaluating, given the enormous emission reductions resulting from the use of low sulfur gasoline, and given that some refineries will trigger major NSR solely as a result of the process changes needed to produce this new gasoline. Finally, EPA seeks comment on whether providing the ability to use the emissions reductions resulting from the use of low sulfur gasoline in vehicles as offsets for refineries producing low sulfur gasoline can be limited to this specific situation. Specifically, EPA requests comment on the concern that providing this option to refineries would allow the use of such emissions reductions as offsets for other stationary sources.

As discussed above, we believe that refineries in ozone nonattainment areas could be the most likely to trigger major NSR review, based on net emission increases of NO_X and/or VOCs. The proposed Tier 2/gasoline sulfur control program is expected to result in over

500,000 tons of NO_X reductions and over 100,000 tons of VOC reductions nationwide in 2004 (the first year of implementation), as well as substantial reductions in particulate matter and sulfur dioxide, as described elsewhere in this document and the draft Regulatory Impact Analysis.[58] In a given nonattainment area, the program could result in hundreds to thousands of tons of NO_X and VOC reductions, depending on the inventory of cars and light-trucks in the area. For example, for the New York metropolitan area, EPA projects NO_X emission reductions of 7,344 tons and VOC emission reductions of 1,285 tons in 2004 resulting from the proposed Tier 2/gasoline sulfur control program.[59] We anticipate that only a small fraction of these total emission reductions in a given area would be needed for use as offsets for refineries implementing gasoline sulfur control projects.

- *Model permits and permit applications.* It may be possible to develop an individual, or series of, model permits or permit applications for gasoline desulfurization projects. Rather than each individual refinery having to develop its own permit application from scratch, a generic permit application form could be developed to address common issues. To file a major source application, a refinery would only need to fill in the blanks as they may relate to case-specific assessments, such as air quality impacts. Similarly, a model permit could contain all necessary compliance measures avoiding the time spent in developing individual permit conditions. Model permits or permit applications would serve as templates, thereby eliminating much of the time and uncertainty associated with processing each application.
- *EPA refinery permitting teams.* We could establish a team of experts to be available as a resource, as needed, to refineries and state/local agencies to troubleshoot permitting issues that may develop with individual applications. The team could be made up of EPA permitting experts empowered to make decisions and resolve issues quickly.

In addition to the above opportunities to streamline the permitting process, we encourage states to process a refinery's request to implement changes at a facility to meet gasoline desulfurization requirements as a priority and on an expedited basis. Priority treatment, in combination with the above opportunities to streamline the process, would ensure that permit applications associated with gasoline desulfurization changes are processed as expeditiously as possible. Given the enormous environmental benefits that we estimate would be achieved as a result of the proposed gasoline sulfur control requirements, we believe such expedited and special processing is appropriate.

ii. *Title V Operating Permit Program.*

We recognize that the changes to be made by refiners to implement gasoline sulfur controls typically would involve not only NSR preconstruction permitting requirements but also those of the title V operating permit program. Title V requires owners or operators of ''major'' and certain other sources to obtain an operating permit—a document that identifies all emissions units, their applicable requirements as developed in accordance with the Clean Air Act, and monitoring and other permit conditions to provide a reasonable assurance of compliance with each of the applicable requirements on an ongoing basis. Most of the refiners likely are ''major'' sources subject to title V, due to their plant-wide level of emissions. As with other process changes, prior to implementing gasoline sulfur controls, refiners would need to work with their state, local, or tribal permitting agency to determine what requirements apply and what changes might be required to the source's title V permit application or permit (if one has been issued).

A critical element of any successful title V permitting strategy to accomplish the necessary desulfurization is how best to integrate the procedural and substantive requirements of the title V and NSR permit programs. We believe the title V permitting process provides an excellent opportunity to accomplish this integration and to impart greater certainty into the ultimate approvability of a gasoline desulfurization project under both permit programs. Depending on a specific permitting authority's program and when the desulfurization activity would occur relative to the issuance of the refinery's initial title V permit, the NSR preconstruction permit and the title V permit processes might be done in parallel or in sequence.

Where the title V permit is issued before the desulfurization activity commences, this permit must be updated before operation of the changes that would also be subject to NSR. In this case, we suggest that the preconstruction permit review process, managed by the permitting authority, be merged with the title V permit revision process so as to satisfy the procedural safeguards and the same substantive requirements of the NSR and title V programs at the same time.[60] If this is done, the title V permit may be administratively amended to incorporate the contents of the NSR permit prior to operation of the desulfurization process changes. Where the appropriate NSR action (major or minor) approving the desulfurization changes precedes the issuance of a source's initial title V permit, the applicable NSR process can still be ''enhanced'' to address title V obligations. Here, in order to determine approvability under both title V and NSR, the permitting authority can issue a separate title V permit specifically for the desulfurization project in advance of the title V permit that will be issued subsequently for the rest of the site. Finally, if issuance of the title V permit issuance for the entire source would precede the NSR construction, depending on several factors, the permitting authority could conduct simultaneous permit processes to accomplish preconstruction approval of the desulfurization project and title V approval for the operation of the project in conjunction with the entire refinery source.

Beyond synchronizing when the two permit programs would be implemented, we recommend that permitting authorities take approaches in the substantive permitting of the desulfurization projects that will both assure compliance with all applicable air requirements and result in a more flexible and efficient permit design. We encourage that the approaches in the

[58] Although these emission reduction estimates are for the combined Tier 2 emission standards/gasoline sulfur control program, in 2004, nearly all these emission reductions would be attributed solely to vehicles fueled by low sulfur gasoline, since vehicles meeting the Tier 2 emission standards would comprise only a small fraction of the vehicle fleet.

[59] See draft Regulatory Impact Analysis, Chapter III.

[60] The concept of a merged NSR/title V process refers to the combination of the title V review process with any otherwise applicable state preconstruction review process, where such process satisfies the procedural requirements of the title V's permit revision, permit review, and public participation provisions. Example state review processes that may be eligible for merger include, but are not limited to, preconstruction review of major or minor NSR, source-specialized State Implementation Plan revisions, and procedures implementing section 112(g) of the Clean Air Act. Under a merged process, activities are only presented in a public forum once, rather than in sequence, to avoid duplication of process. Upon completion of the merged process, a successful project would have met all federal permitting requirements, including review by the public, EPA and affected States, and opportunities for EPA objection and public petition, and can implement both processes without delay. Qualifying activities that have received preconstruction review permits meeting the requirements of 40 CFR 70.7(d)(1)(v) may be incorporated into title V permits as administrative permit amendments.

title V ''White Papers'' [61] be considered to focus both the content of title V applications and permits. In particular, we recommend that permitting authorities and owners or operators of refineries consider the ''streamlining'' of multiple applicable requirements applying to the same project. Under the streamlining concept, where multiple applicable requirements apply to the same emission unit(s), the permitting authority may develop one emission limit (with associated monitoring, recordkeeping, and reporting) that assures compliance with all applicable requirements. For example, several aspects of the control requirements necessary to implement our maximum available control technology (MACT) and new source performance standards (NSPS) requirements, State Implementation Plan (SIP), and NSR programs (including both major and minor NSR, as applicable) could be considered for streamlining per White Paper Number 2. Where successful, this streamlining will result in a single control requirement (or emission limit), coupled with appropriate monitoring, recordkeeping, reporting, and testing requirements that yield a reasonable assurance of compliance for all subsumed requirements.[62]

We also are willing to explore applying to the varying situations of sulfur removal at refineries certain permit design approaches that have previously been limited to some permitting pilot projects. In particular, in partnership with permitting authorities, we have been working with selected industries at specific sites to conduct Pollution Prevention in Permitting Project (P4) pilots. These projects respond to the Administration's goals for reinvention in order to implement environmental permit programs in a more streamlined fashion, while assuring required levels of environmental protection. Based on our prior experience with these regulatory reinvention projects, permit design options for refiners implementing gasoline desulfurization projects might include, but are not limited to, any of the following approaches:

- Advance approvals of certain types of changes in title V, including those subject to minor NSR. [63]
- Provisions that where met would prevent another requirement from applying (e.g., plant wide applicability limits (as noted above) to address potential major NSR applicability).
- Model permit conditions, such as a presumptive, streamlined approach to meet all applicable control technology requirements to expedite permitting decisions, where applicable.
- Adding terms to a title V permit so as to preauthorize a faster permit revision process where one is necessary to add further details within an approved approach (e.g., the minor instead of significant permit modification process).
- Permitting the worst-case emissions scenario to address all applicable requirements applying in a range of possible operating scenarios or to prevent certain requirements from applying.
- Permitting alternative compliance options where an owner or operator of a source needs the flexibility to vary the compliance approach with changing refinery conditions.
- Using pollution prevention approaches to facilitate compliance with applicable requirements and/or required permit terms.

We recognize that the situations for refineries affected by the proposed gasoline sulfur control program can vary widely (e.g., sulfur level in the gasoline, size of the stream, air quality status of the area, etc.), and that the actual permit approach for an individual refinery may be a combination of certain options outlined above and previously for streamlining NSR. Any title V approach must, however, assure compliance with all applicable requirements linked to the necessary construction and provide a meaningful opportunity for all affected parties to review the appropriateness of a proposed approach as it would apply to a particular site. For example, where new desulfurization units would be required and would be well controlled so as to result in emissions below the threshold for triggering major NSR, then an advance approval of minor NSR requirements in combination with certain operationally limiting conditions might be an appropriate strategy. Where the addition of such a unit would trigger major NSR, then the strategies that combine the reviews and streamline the requirements of both title V and major NSR offer promise. In a few cases, reblending of high sulfur gasoline blend stocks, blending in low sulfur oxygenates, or using sweeter crude oil might be sufficient to achieve the necessary sulfur reductions and require few, if any, additional title V permit terms to implement.

iii. *EPA Assistance to Explore Permit Streamlining Options and Solicitation of Comment.*

We are committed to exploring the possible approaches described above. Accordingly, if there is sufficient interest and need, as expressed in comments on this proposed rule, within the refining industry and among state permitting authorities, we will hold a P4/flexible permit workshop focused on the permitting of the refining industry arising from the gasoline desulfurization program. Additionally, should a permitting authority and owners or operators of affected facilities within a common jurisdiction express a desire for a specific flexible permit project aimed at the development of permit language to facilitate refinery activities to reduce gasoline sulfur, then in accordance with already established principles for initiating similar permit projects, we would be willing to work with a designated refinery. We intend that the approaches derived from such efforts could then serve as a template as needed for use by other refineries and state permitting authorities, provided the approaches are modified to conform with all applicable state title V and NSR requirements.

We believe that application of one or more of the approaches described in today's document would reduce any burden of meeting NSR permit requirements and revisions to title V permit applications or permits to incorporate the gasoline desulfurization requirements adopted in the final rule. However, the use of one or more of these approaches would have accompanying resource requirements. For example, it is possible that the initial resources required to establish a PAL, and the attendant monitoring, recordkeeping and reporting requirements, could involve as much time and resources as associated with a typical NSR permit. However, once established, a PAL could provide more flexibility and minimize future resource demands than more traditional permit approaches. Accordingly, we request that permitting authorities, owners or operators of affected facilities, and the public comment on whether use of the

[61] *White Paper for Streamlined Development of Part 70 Permit Applications,* Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards, U.S. EPA, July 10, 1995 and *White Paper Number 2 for Improved Implementation of the Part 70 Operating Permits Program*, Lydia N. Wegman, Deputy Director, Office of Air Quality Planning and Standards, U.S. EPA, March 5, 1996.

[62] See Section II.A. of White Paper Number 2.

[63] Advance approval means that a particular project (or class of projects) like one to accomplish gasoline desulfurization and its support activities would be preapproved for title V purposes before its actual construction, provided that the terms of the title V permit governing the advance approval are met. The Agency has a possible non-binding interpretation of the Title V regulations that would provide for the advance approval of certain new emission units and control devices. See 63 FR 50279, 50315–20 (Sept. 21, 1998) (Section IV.L., Permitting and Compliance Options/Change Management Strategy, in National Emission Standards for Hazardous Air Pollutants for Source Categories: Pharmaceuticals Production).

approaches described in today's document will achieve appropriate streamlining of controls and requirements arising out of this rule and meet the objectives of the NSR and title V permitting programs.

c. *Should Hardship Relief Be Available?* Elsewhere in this document (Section IV.C.3.b.), we propose a hardship provision that would apply to small refiners. EPA seeks additional comment on whether it should adopt a hardship provision allowing for compliance with standards less stringent than those proposed today during the early years of the program. While EPA believes that it is feasible for most refiners to meet the proposed standard by 2004, the Agency is seeking comment on whether it may be appropriate to allow refiners with substantial economic hardship circumstances to apply for relief from compliance with the sulfur standard for a limited time period.

Such a hardship provision would need to contain appropriate criteria to limit the provision to a narrowly drawn set of circumstances. This might include criteria such as ability to raise capital to make necessary refinery investments in time for 2004, given the current size and ownership of the refinery, the physical characteristics of the refinery, the volume of gasoline at issue, ability to purchase credits to comply, and any efforts by the refiner to limit sulfur that are already underway or have been attempted. The provision would also need to contain criteria to ensure that it would not undermine the emissions reduction goals of the Tier 2/sulfur program and would not allow large amounts of gasoline with sulfur levels significantly above 30 ppm into the market. For example, this might include a volume limit on the use of less stringent standards in hardship circumstances. It would also need to include an endpoint, so that the relief is short-term and the refinery would then have to meet the same standard as all other refineries. For example, EPA would not expect that hardship relief will be needed beyond 2009.

Under such a provision, we expect that refiners would be subject to a reasonable level of control, albeit less stringent than the proposed standards. At a minimum, sulfur levels at a particular refinery should not be permitted to be higher than 1997–1998 baseline levels and in no event should the average sulfur level be greater than 300 ppm. EPA also seeks comment on the appropriate time frame for allowing relief in hardship circumstances. EPA solicits comments on whether any refiners would encounter significant hardship in meeting the proposed standard. EPA solicits comment on the implications of any such hardship provision on small refiners and its relationship to the small refiner provisions proposed in this document. Finally, EPA seeks comment on the implications of a hardship provision on the proposed ABT program.

5. Consideration of Diesel Fuel Control

As explained in Section IV.B. above, the proposed Tier 2 standards would apply to both gasoline- and diesel fuel-fueled vehicles. Currently very few light-duty vehicles operate on diesel fuel. Given what we know about gasoline vehicles, we believe it is reasonable to anticipate that the use of exhaust aftertreatment devices may be required, and that these technologies may have similar sensitivities to sulfur that the catalysts used on gasoline engines have. However, we do not yet have enough information to be able to conclude that diesel sulfur levels need to be reduced in the same time frame that Tier 2 vehicles are introduced. A decision to require reductions in diesel sulfur levels could have significant implications for the refining industry, both because it would likely require capital expenditures over and above the significant costs that would be incurred in controlling gasoline sulfur, and because for some refiners concurrent control of gasoline and diesel sulfur may be the most economical solution. Hence, due to the implications for automotive manufacturers and for diesel fuel producers, a decision on whether to require diesel fuel sulfur reductions needs to be made as soon as possible.

Automobile and diesel engine manufacturers and state air quality agencies have recently asked us to set new fuel quality requirements for diesel fuel used in highway vehicles.[64] The manufacturers believe that such requirements, especially controlling diesel fuel sulfur content to very low levels, could produce large environmental benefits by enabling dramatically lower-emitting diesel engines equipped with exhaust aftertreatment devices. The viability of such technologies would, of course, affect the feasibility of the proposed Tier 2 emission standards for diesel vehicles. Currently, highway diesel fuel is regulated under standards we set in 1990. These standards, which became effective in 1993, limit the concentration of sulfur in diesel fuel to a maximum of 500 ppm; they also control the amount of aromatic compounds in the fuel (55 FR 34120, August 21, 1990).

Diesel engine manufacturers have argued that implementing Tier 2 standards without concurrent diesel fuel changes would be unfair to diesels because diesel fuel quality is worse than gasoline fuel quality, especially considering that the Tier 2 rulemaking includes proposed improvements in gasoline quality to enable advanced three-way catalytic converters. Some argue that, beyond fuel-neutrality considerations, diesel fuel quality improvement is needed to combat global warming because it will facilitate the marketing of more diesel vehicles and, in their opinion, thereby reduce emissions of global warming gases. Others counter that such benefits are illusory and that diesel vehicles should be discouraged because diesel exhaust is a serious health hazard, a hazard that improvements in fuel quality would do little to mitigate.

To address the issue of diesel fuel changes, we will issue an Advance Notice of Proposed Rulemaking (ANPRM) in the near future. We encourage interested parties to review and comment on the issues raised in the ANPRM. On the basis of this information, if appropriate, we plan to publish a proposal on standards for diesel fuel in the next several months. This would provide some degree of clarity regarding our plans in this area in time to help affected industries to then make their own plans without undue disruption. This is especially important for the petroleum refining industry in planning capital outlays to accomplish sulfur reduction in gasoline, and potentially diesel fuel, at the most economical point in the refining process.

Several diesel vehicle manufacturers have raised the concern that unless or until lower sulfur diesel fuel is available, the sulfate component of diesel PM may be particularly difficult to control to very low emission levels. They have encouraged us to express the proposed PM standards in terms of non-sulfate PM to provide manufacturers flexibility in how they balance the control of sulfate and non-sulfate PM components.

[64] See the following contained in the docket for this rulemaking: Letter from Robert J. Eaton, Chrysler Corporation, Alex Trotman, Ford Motor Company and John F. Smith, Jr., General Motors Corporation, to Vice President Al Gore, July 16, 1998; ''STAPPA/ALAPCO Resolution on Sulfur in Diesel Fuel,'' October 13, 1998; Letter from S. William Becker, Executive Director of STAPPA/ALAPCO, to Carol Browner, Administrator of U.S. EPA, October 16, 1998; Letter from Jed R. Mandel, Engine Manufacturers Association, to Margo T. Oge, Director, Office of Mobile Sources, EPA, November 6, 1998.

We request comment on such an approach, including specific comments on the following:

- Whether or not such an approach could be justified on an air quality basis, given the potential for very high sulfate PM emissions due to unrestrained sulfate production in diesel catalytic converters;
- Whether such an approach should be limited to the interim PM standards and be discontinued when the Tier 2 standards are fully phased in;
- How this approach should be phased out if low-sulfur diesel fuel were to be phased in; and
- Whether a cap on sulfate PM should accompany such an approach and what value (in grams per mile) would be appropriate for a cap.

D. What Are the Economic Impacts, Cost Effectiveness and Monetized Benefits of the Proposal?

Consideration of the economic impacts of new standards for vehicles and fuels has been an important part of our decision making process for this proposal. The following sections describe first the costs associated with meeting the new vehicle standards and the new fuel standards. This will be followed with a discussion of the cost effectiveness of the proposal. Lastly, we will discuss the results of a preliminary benefit-cost assessment that we have prepared.

Full details of our cost analyses, including information not presented here, can be found in the Draft RIA associated with this rule. We invite comments on all aspects of these analyses.

1. What Are the Estimated Costs of the Proposed Vehicle Standards?

To perform a cost analysis for the proposed standards, we first determined a package of likely technologies that manufacturers could use to meet the proposed standards and then determined the costs of those technologies. In making our estimates we have relied both on publicly available information, such as that developed by California, and confidential information supplied by individual manufacturers.

In general, we expect that the Tier 2 standards will be met through refinements of current emissions control components and systems rather than through the widespread use of new technology. Furthermore, lighter vehicles will generally require less extensive improvements than larger vehicles and trucks. More specifically, we anticipate a combination of technology upgrades such as the following:

- Improvements to the catalyst system design, structure, and formulation plus some increase in average catalyst size and loading.
- Air and fuel system modifications including changes such as improved microprocessors, improved oxygen sensors, leak free exhaust systems, air assisted fuel injection, and calibration changes including improved precision fuel control and individual cylinder fuel control.
- Engine modifications, possibly including an additional spark plug per cylinder, an additional swirl control valve, or other hardware changes needed to achieve cold combustion stability.
- Increased use of fully electronic exhaust gas recirculation (EGR).
- Increased use of secondary air injection for 6 cylinder and larger engines.
- Heat optimized exhaust pipes and low thermal capacity manifolds.

Using a typical mix of changes for each group, we projected costs separately for LDVs, the different LDT classes, and for different engine sizes (4, 6, 8-cylinder) within each class. For each group we developed estimates of both variable costs (for hardware and assembly time) and fixed costs (for R&D, retooling, and certification).

Cost estimates based on the current projected costs for our estimated technology packages represent an expected incremental cost of vehicles in the near-term. For the longer term, we have identified factors that would cause cost impacts to decrease over time. First, since fixed costs are assumed to be recovered over a five-year period, these costs disappear from the analysis after the fifth model year of production. Second, the analysis incorporates the expectation that manufacturers and suppliers will apply ongoing research and manufacturing innovation to making emission controls more effective and less costly over time. Research in the costs of manufacturing has consistently shown that as manufacturers gain experience in production, they are able to apply innovations to simplify machining and assembly operations, use lower cost materials, and reduce the number or complexity of component parts.[65] These reductions in production costs are typically associated with every doubling of production volume. Our analysis incorporates the effects of this ''learning curve'' by projecting that the variable costs of producing the Tier 2 vehicles decreases by 20 percent starting with the third year of production. We applied the learning curve reduction only once since, with existing technologies, there would be less opportunity for lowering production costs than would be the case with the adoption of new technology.

We have prepared our cost estimates for meeting the Tier 2 standards using a baseline of NLEV technologies for LDVs, LDT1s, and LDT2s, and Tier 1 technologies for LDT3s and LDT4s. These are the standards that vehicles would be meeting in 2003.[66] We have not specifically analyzed smaller incremental changes to technologies that might occur due to the interim standards between the baseline and Tier 2. In many cases, we believe these changes will not be significant based on current certification levels. For others, manufacturers can use averaging and other program flexibilities to avoid redesigning vehicles twice within a relatively short period of time. We believe this is likely to be an attractive approach for manufacturers due to the savings in R&D and other resources.

For the total annual cost estimates, we projected that manufacturers will start the phase-in of Tier 2 vehicles with LDVs in 2004 and progress to heavier vehicles until all LDT2s meet Tier 2 standards in 2007. For LDT3s and LDT4s, we projected some sales of Tier 2 LDT3s prior to 2008 for purposes of averaging in the interim program and that the phase-in of Tier 2 vehicles would end with LDT4s in 2009.

Finally, we have incorporated what we believe to be a high level of R&D spending at $5,000,000 per vehicle line (with annual sales of 100,000 units per line). We have included this large R&D effort because calibration and system optimization is likely to be a critical part of the effort to meet Tier 2 standards. However, we believe that the R&D costs may be overstated because the projection ignores the carryover of knowledge from the first vehicle lines designed to meet the standard to others phased-in later.

The evaporative emissions standards we are proposing today for LDVs and LDTs are feasible with relatively small cost impacts. We estimate the cost of system improvements to be about $4 per vehicle, for all vehicle classes. This incremental cost reflects the cost of moving to low permeability materials, improved designs or low-loss

[65] ''Learning Curves in Manufacturing,'' Linda Argote and Dennis Epple, Science, February 23, 1990, Vol. 247, pp. 920–924.

[66] Even though the NLEV program ends in the Tier 2 time frame, we have not included the NLEV program costs or benefits in our analysis, since EPA analyzed and adopted NLEV previously.

connectors. R&D for the evaporative emissions standard is included in the R&D estimates given above for the tailpipe standards. We have made no projections of learning curve reductions for the evaporative standard.

Table IV.D.–1 provides our estimates of the per vehicle increase in purchase price for LDVs and LDTs. The near-term cost estimates in Table IV.D.–1 are for the first years that vehicles meeting the standards are sold, prior to cost reductions due to lower productions costs and the retirement of fixed costs. The long-term projections take these cost reductions into account. We have sales weighted the cost differences for the various engine sizes (4-, 6-, 8-cylinder) within each category.

TABLE IV.D.–1.—ESTIMATED PURCHASE PRICE INCREASES DUE TO PROPOSED TIER 2 STANDARDS

	LDV	LDT1	LDT2	LDT3	LDT4
Tailpipe standards:					
Near-term (year 1)	$76	$69	$132	$270	$266
Long-term (year 6 and beyond)	46	43	99	214	209
Evaporative Standard	4	4	4	4	4

2. What Are the Estimated Costs of the Proposed Gasoline Sulfur Standards?

As explained in Section IV.C., most refiners will have to install capital equipment to meet the proposed gasoline sulfur standard. Presuming that refiners will want to minimize the cost involved, refiners are expected to desulfurize the gasoline blendstock produced by the fluidized catalytic cracker (FCC) unit. Recent advances have led to significant improvements in hydrotreating technology by CDTECH and Mobil Oil (OCTGAIN) that lower the cost of desulfurizing FCC gasoline; we understand that similar technologies are being developed by other parties. Since these improved desulfurization technologies represent the lowest cost options and are expected to be used by most refiners needing to install desulfurization equipment, we estimated the cost of desulfurization based on their use.

For our analysis, we estimated the cost of lowering gasoline sulfur levels in five different regions of the country (Petroleum Administration Districts for Defense, or PADD), starting from the current regional average in each PADD down to 30 ppm. We then converted the regional cost to a national average per-refinery cost, and calculated a national aggregate cost and cents-per-gallon cost.

Based on this analysis we estimate that, on average, refiners in the year 2004 would be expected to invest about $45 million for capital equipment and spend about $16 million per year for each refinery to cover the operating costs associated with these desulfurization units. Since this average represents many refineries diverse in size and gasoline sulfur level, some refineries would pay more and others less than the average costs. When the average per-refinery cost is aggregated for all the gasoline expected to be produced in this country in 2004, the total investment for desulfurization processing units is estimated to be about $4.7 billion dollars, and operating costs for these units is expected to be about $1.5 billion per year. We believe that the $4.7 billion in capital costs would be spread over several years by the refiners' participation in the proposed averaging, banking, and trading program.

These capital and operating costs represent our estimates for domestic costs. While we think that many foreign refiners might incur capital costs to meet the requirements of our gasoline sulfur program, particularly in light of similar programs being enacted internationally, others will argue that most foreign refiners would not incur new costs as a result of our program because they can simply send the lowest-sulfur fraction of their current production to the U.S. Furthermore, some will argue that most foreign refiners do not face the same permitting limitation and environmental and other regulatory costs that domestic refiners face, and thus that their costs of producing low sulfur gasoline will be minimal even if some investment is required. While we have developed cost estimates with and without consideration of possible costs attributed to imported gasoline, our estimates of national and average costs do not include any costs attributed to foreign refiners.

Using our estimated capital and operating costs we calculated the average per-gallon cost of reducing gasoline sulfur down to 30 ppm. Using a capital cost amortization factor based on a seven percent rate of return on investment, and including no taxes, we estimated the average national cost for desulfurizing gasoline to initially be about 1.7 cents per gallon. This cost is the cost to society of reducing gasoline sulfur down to 30 ppm that we used for estimating cost effectiveness. If we amortize the costs based on a rate of return on investment of six to ten percent and a tax rate of 39 percent, which may more closely represent the actual economic situation facing refiners today, the average national cost for desulfurizing gasoline down to 30 ppm would be 1.7–1.9 cents per gallon.

We anticipate that these costs will decrease in future years due to improvements in technology, similar to the learning curve improvements discussed above for vehicle cost. This improvement is estimated to result in a 20 percent reduction in operating costs after the second complete year of use. This estimated rate of improvement is similar to previous cost reductions observed with desulfurization technologies as they were being developed.

Additional cost reduction is expected as refiners increase the throughput (debottleneck) of their refineries to lower their per-gallon fixed costs. This increase in throughput for the industry as a whole is termed capacity creep and it is has allowed a shrinking number of U.S. refineries to handle the increasing demand for refined products. Our analysis presumes that as an industry, refiners will debottleneck their refineries at a rate consistent with the forecasted increase in gasoline demand, which is about 2 percent per year. Thus, the fixed operating cost, and a portion of the capital costs for these desulfurization technologies, would decrease over time on a per gallon basis as the volume of gasoline processed at each refinery increased.

Table IV.D.–2 below summarizes our estimates of per-gallon gasoline cost increases for the years 2004, 2010 and 2015.

TABLE IV.D.–2.—ESTIMATED PER-GALLON COST FOR DESULFURIZING GASOLINE IN FUTURE YEARS

Year	Cost (cents/ gallon)
2004	1.7
2010	1.5
2015	1.4

3. What Are the Aggregate Costs of the Tier 2/Gasoline Sulfur Proposal?

Using current data for the size and characteristics of the vehicle fleet and making projections for the future, the per-vehicle and per-gallon fuel costs described above can be used to estimate the total cost to the nation for the proposed emission standards in any year. Figure IV.D.–1 portrays the results of these projections.[67]

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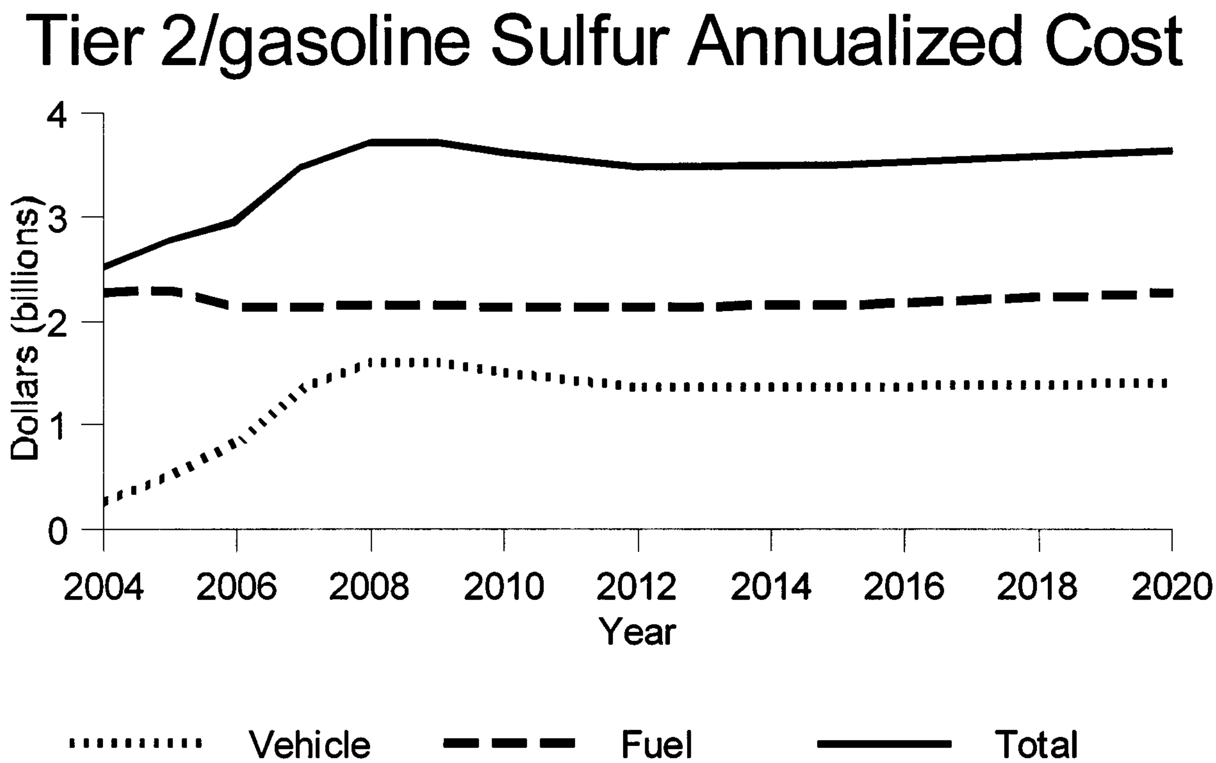
Figure IV.D. -1



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As can be seen from the figure, the annual cost starts out at just over $2.5 billion per year and increases over the phase-in period to a maximum of $3.7 billion in 2008. Thereafter, the annual cost declines to a level of about $3.5 billion. The effect of projected growth in vehicle sales and fuel consumption causes a slow, gradual rise in annual cost to set in after about 2012.

4. How Does the Cost Effectiveness of This Program Compare to Other Programs?

This section summarizes the cost effectiveness analysis done by EPA and its results. The purpose of this assessment is to determine whether reductions from the vehicle and fuel controls are cost effective, taking into consideration alternative means of attaining or maintaining the national primary ambient air quality standards. This involves a comparison of our proposed program not only with past measures, but with other new measures that might be employed to attain and maintain the NAAQS. Both EPA and states have already adopted numerous control measures, and remaining measures tend to be more expensive than those previously employed. Therefore, there is no single cost effectiveness level that defines what is acceptable. Rather, as we employ the most cost effective available measures first, more expensive ones tend to become necessary over time.

a. *What Is the Cost Effectiveness of This Program?* We have calculated the per-vehicle cost effectiveness of the exhaust/gasoline sulfur standards and the evaporative emission standards, based on the net present value of all costs and emission reductions over the life of an average Tier 2 vehicle subject to today's proposal. As described earlier in the discussion of the cost of this proposal, the cost of complying with the new standards will decline over time as manufacturing costs are reduced and amortized capital investments are recovered. To show the effect of declining cost on the cost effectiveness, we have developed both near term and long term cost effectiveness values. More specifically, these correspond to

[67] Figure IV.D.–1 is based on the amortized costs from Tables IV.D.–1 and IV.D.–2. Actual capital investments, particularly important for fuels, would occur prior to and during the initial years of the program, as described above in section IV.D.2.

vehicles sold in years one and six of the vehicle and fuel programs. Vehicle cost is constant from year six onward. Fuel costs per gallon continue to decline slowly in the years past year six; however, the overall impact of this decline is small and we have decided to use year six results for our long term cost effectiveness. Chapter V of the draft RIA contains a full description of this analysis, and you should look in that document for more details on the results summarized here.

Table IV.D.–3 summarizes the net present value lifetime cost, NMHC + NO_X emission reduction and cost effectiveness results for the Tier 2/ gasoline sulfur proposal using sales weighted averages of the costs (both near term and long term) and emission reductions of the various vehicle classes affected.

Table IV.D.–3 also displays cost effectiveness values based on two approaches to account for the small reductions in SO_2 and tailpipe emitted sulfate particulate matter (PM) associated with the reduction in gasoline sulfur. While these reductions are not central to the proposal and are therefore not displayed with their own cost effectiveness, they do represent real emission reductions due to the proposed rule. The first set of cost effectiveness numbers in Table IV.D.–3 simply ignores these reductions and bases the cost effectiveness on only the NMHC + NO_X reductions from Tier 2/ gasoline sulfur. The second set accounts for these reductions by crediting some of the cost of the program to SO_2 and PM reduction. The amount of cost allocated to SO_2 and PM is based on the cost effectiveness of SO_2 and PM emission reductions from other EPA actions. You may refer to the RIA for details about these actions and how the specific allocations were developed.

TABLE IV.D.–3.—COST EFFECTIVENESS OF THE PROPOSED STANDARDS (1997 DOLLARS)

Cost basis	Discounted lifetime vehicle and fuel costs	Discounted lifetime NMHC + NO_X reduction (tons)	Discounted lifetime cost effectiveness per ton	Discounted lifetime cost effectiveness per ton with SO_2 and direct PM credit[a]
Near term cost (production year 1)	$230	0.108	$2,134	$1,599
Long term cost (production year 6)	188	0.109	1,748	1,213

[a] $54 credited to SO_2 ($4800/ton), $4 to direct PM ($10,000/ton).

b. *How Does the Cost Effectiveness of this Program Compare with Other Means of Obtaining Mobile Source NO_X + NMHC Reductions?* In comparison with other mobile source control programs, we believe that today's proposal represents the most cost effective new mobile source control strategy currently available that is capable of generating substantial NO_X + NMHC reductions. This can be seen by comparing the cost effectiveness of today's program with a number of new mobile source standards that EPA has adopted in recent years. Table IV.D.-4 summarizes the cost effectiveness of several recent EPA actions.

TABLE IV.D.-4.—C/E OF PREVIOUSLY IMPLEMENTED MOBILE SOURCE PROGRAMS

Program	$/ton NO_X+NMHC
2004 Highway HD Diesel stds	300
Nonroad Diesel engine stds	410–650
Tier 1 vehicle controls	1,980–2,690
NLEV	1,859
Marine SI engines	1,128–1,778
On-board diagnostics	2,228

(Costs adjusted to 1997 dollars.)

We can see from the table that the cost effectiveness of the Tier 2/gasoline sulfur standards falls within the range of these other programs. Engine-based standards (the 2004 highway heavy-duty diesel standards, the nonroad diesel engine standards and the marine spark-ignited engine standards) have generally been less costly than Tier 2/gasoline sulfur. Vehicle standards, most similar to today's proposal, have values comparable to or higher than Tier 2/ gasoline sulfur.

It is tempting to look at the engine standards and conclude that more reductions at a similar low cost effectiveness should still be available. This is especially true for the two largest categories (highway and nonroad diesel engines) where new standards have been adopted that were highly cost effective. However, cost effectiveness was not a limiting consideration in either case. Rather, the level of the standards selected was based primarily on technical feasibility in the time available. That is, the maximum level of control that we found to be feasible in these actions was driven more by what technology we believed would be available than by cost. It will be important to consider the potential for further control in these categories as we move forward.

We do not believe that significant further control is available from highway or nonroad diesel engines through more stringent standards at the same cost effectiveness that these standards realized, in the time frame proposed. Based on current knowledge, the next generation of controls for these diesel engines would require advanced after-treatment devices, still in the research and development phase. Such controls have not yet been employed and when they become available will be more costly and will have difficulty functioning without changes to diesel fuel. We fully expect that, as the development of new technology progresses and cost declines, future new standards for both of these source categories will be developed. But we also expect that the cost effectiveness of future standards will be higher and is not likely to be significantly less than the cost effectiveness of today's proposal.

On the light duty vehicle side, the last two sets of standards were Tier 1 and NLEV, which had cost effectiveness comparable to or higher than Tier 2/ gasoline sulfur. Compared to engines, these levels reflect the advanced (and more expensive) state of vehicle control technology, where standards have been in effect for a much longer period than for engines. In fact, considering the increased stringency of the Tier 2 standards,[68] it is remarkable that the cost effectiveness of Tier 2/gasoline sulfur is in the same range as these actions. Based on these results, Tier 2/ gasoline sulfur appears to be a logical and consistent next step in vehicle control.

In conclusion, we believe that the Tier 2/gasoline sulfur proposal is a cost effective program for mobile source NO_X + NMHC control. We are unable to

[68] Tier 2/gasoline sulfur will yield about a 75% reduction in NO_X emissions compared to NLEV vehicles.

identify another mobile source control program that would be more cost effective than Tier 2/gasoline sulfur for making substantial further progress in reducing NO_X + NMHC emissions.

c. *How Does the Cost Effectiveness of this Proposed Program Compare with Other Known Non-Mobile Source Technologies for Reducing NO_X +* NMHC? In evaluating the cost effectiveness of the Tier 2/gasoline sulfur proposal, we also considered whether our proposal is cost effective in comparison with alternative means of attaining or maintaining the NAAQS other than mobile source programs. As described below, we have concluded that Tier 2/gasoline sulfur is cost effective considering the anticipated cost of other technologies that will be needed to help attain and maintain the NAAQS.

For purposes of estimating the cost of implementing the new ozone and PM NAAQS, the Agency assumed certain baseline controls and compiled a list of additional known technologies that could be considered in devising emission reductions strategies.[69] Through this broad review, over 50 technologies were identified as reducing NO_X or VOC. The average cost effectiveness of these technologies varied from hundreds of dollars a ton to tens of thousands of dollars a ton. The Agency selected from this list all those technologies that could be applied with an average cost effectiveness of $10,000/ton or less, and showed that substantial progress toward attainment could be made when operating within that limit.

While many areas still remained in nonattainment under the NAAQS analysis, we assumed that other methods would be identified in the future that on average could help achieve the NAAQS at $10,000 per ton or less. We believe that Tier 2/gasoline sulfur is one of those methods. In fact, it will deliver critical further reductions that are not readily obtainable by any other means known to the Agency. By way of comparison, if all of the technologies identified for the NAAQS analysis costing less than $10,000/ton were implemented nationwide, they would produce NO_X emission reductions of about 2.9 million tons per year. The Tier 2/gasoline sulfur proposal by itself will generate about 2.8 million tons per year once fully implemented. To obtain significant further reductions using the other technologies identified in the NAAQS analysis rather than Tier 2/gasoline sulfur could mean adopting measures costing well beyond $10,000/ton. Given the continuing need for further emission reductions, we believe that Tier 2/gasoline sulfur control is clearly a cost effective approach, in addition to those technologies assumed for the NAAQS analysis, for attaining and maintaining the NAAQS.

We recognize that the cost effectiveness calculated for Tier 2/gasoline sulfur is not strictly comparable to a figure for measures targeted at nonattainment areas, since Tier 2/gasoline sulfur is a nationwide program. However, there are several additional considerations that have led us to conclude that Tier2/gasoline sulfur is cost effective considering alternative means of attaining and maintaining the NAAQS.

First, given the fact that Tier 2/gasoline sulfur is at most only 20 percent as costly per ton as the NAAQS figure for additional control measures, we believe that there can be little doubt that the cost effectiveness of Tier 2/gasoline sulfur is well within the cost effectiveness range that the NAAQS cost analysis anticipated for unspecified additional technologies that will be needed to attain the NAAQS—technologies that the analysis noted might be applied in limited areas or nationwide. Furthermore, as a national program, Tier 2/gasoline sulfur can be implemented as a single unified rule without the need for individual action by each of the states. Moreover, as noted above, for states to obtain further substantial emission reductions beyond those identified in the NAAQS could mean adopting measures costing well beyond $10,000/ton, something that few areas of the country to date have done.

In dealing with the question of comparing local and national programs, it is also relevant to point out that, because of air transport, the need for NO_X control is a broad regional issue not confined to non-attainment areas only. To reach attainment, future controls will need to be applied over widespread areas of the country. In the analyses supporting the recent NO_X standards for highway diesel engines,[70] we looked at this question in some detail and concluded that the regions expected to impact ozone levels in ozone nonattainment areas accounted for over 85% of total NO_X emissions from a national heavy-duty engine control program. Similarly, NO_X emissions in attainment areas also contribute to particulate matter nonattainment problems in downwind areas. Thus, the distinction between local and national control programs for NO_X is less important than it might appear.

Finally, the statute indicates that in considering the cost effectiveness of Tier 2/gasoline sulfur EPA should consider not only attainment, but also maintenance of the standards. Tier 2/gasoline sulfur—unlike nonattainment area measures—will achieve attainment area reductions that, among other effects, will help to maintain air quality that meets the NAAQS. These reductions relate not only to the ozone and PM NAAQS, but also to SO_2 and NO_2, and to CO.

In summary, given the array of controls that will have to be implemented to make progress toward attaining and maintaining the NAAQS, we believe that the weight of the evidence from alternative means of providing substantial NO_X + NMHC emission reductions indicates that the Tier 2/gasoline sulfur proposal is cost effective. This is true from the perspective of other mobile source control programs or from the perspective of other stationary source technologies that might be considered.

5. Does the Value of the Benefits Outweigh the Cost of the Proposed Standards?

While relative cost effectiveness is the principal economic policy criterion established for these standards in the Clean Air Act (see CAA 202(i)), further insight regarding the merits of the proposed standards can be provided by benefit-cost analysis. The purpose of this section is to summarize the methods we used and results we obtained in conducting a preliminary analysis of the economic benefits of the proposed standards, and to compare these economic benefits with the estimated costs of the proposal. In summary, the results of our analysis indicate that the economic benefits of the proposed standards will likely exceed the costs of meeting the standards by a substantial margin, and the significant uncertainties underlying the analysis are unlikely to alter this outcome of positive net benefits.

a. *What Is the Purpose of this Benefit-Cost Comparison?* Benefit-cost analysis (BCA) is a useful tool for evaluating the economic merits of proposed changes in environmental programs and policies. In its traditional application, BCA

[69] ''Regulatory Impact Analyses for the Particulate Matter and Ozone National Ambient Air Quality Standards and Proposed Regional Haze Rule,'' Appendix B, ''Summary of control measures in the PM, regional haze, and ozone partial attainment analyses,'' Innovative Strategies and Economics Group, Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, NC, July 17, 1997.

[70] Final Regulatory Impact Analysis: Control of Emissions of Air Pollution from Highway Heavy-Duty Engines, September 16, 1997.

estimates the economic ''efficiency'' of proposed changes in public policy by organizing the various expected consequences and representing those changes in terms of dollars. Expressing the effects of these policy changes in dollar terms provides a common basis for measuring and comparing these various effects. Because improvement in economic efficiency is typically defined to mean maximization of total wealth spread among all members of society, traditional BCA must be supplemented with other analyses in order to gain a full appreciation of the potential merits of new policies and programs. These other analyses may include such things as examinations of legal and institutional constraints and effects; engineering analyses of technology feasibility, performance and cost; or assessment of the air quality need.

In addition to the narrow, economic efficiency focus of most BCAs, the technique is also limited in its ability to project future economic consequences of alternative policies in a definitive way. Critical limitations on the availability, validity, or reliability of data; limitations in the scope and capabilities of environmental and economic effect models; and controversies and uncertainties surrounding key underlying scientific and economic literature all contribute to an inability to estimate the economic effects of environmental policy changes in exact and unambiguous terms. Under these circumstances, we consider it most appropriate to view BCA as a tool to inform, but not dictate, regulatory decisions such as the ones reflected in today's proposal.

Despite the limitations inherent in BCA of environmental programs, we considered it useful to estimate the potential benefits of today's proposed standards both in terms of physical changes in human health and welfare and environmental change, and in terms of the estimated economic value of those physical changes. The BCA presented herein should be considered preliminary, however, due to limitations in the data and models available for analysis in advance of today's proposal. Additional, more refined analysis will be conducted prior to issuance of final standards. This post-proposal analysis will take account of public comments on the proposed standards and this BCA and will also make use of more extensive and refined data and models currently being developed. Our expectation is that the more extended and refined economic analysis conducted prior to final rulemaking will further help inform and guide decisions on the appropriateness of the final rules. Toward this end, we are presenting this preliminary BCA and requesting public comments on the assumptions, data, and modeling efforts supporting the analysis and its results, and the appropriate interpretations and uses of those results.

b. *What Was Our Overall Approach to the Benefit-Cost Analysis?* The basic question we sought to answer in the preliminary BCA was: ''What are the net yearly economic benefits to society of the reduction in mobile source emissions likely to be achieved by today's proposed standards?'' In designing an analysis to answer this question, we adopted an analytical structure and sequence similar to that used in the so-called ''section 812 studies'' [71] to estimate the total benefits and costs of the entire Clean Air Act. Moreover, we used many of the same data sets, models, and assumptions actually used in the Section 812 studies and/or the recent Regulatory Impact Analyses (RIAs) for the Particulate Matter and Ozone National Ambient Air Quality Standards and for the NO_X SIP Call (also known as the Regional Ozone Transport Rule, as discussed in Section III above).[72] By adopting the major design elements, data sets, models, and assumptions developed for the recent RIAs, we have largely relied on methods that have already received extensive review by the public and by other federal agencies. Furthermore, the data sets adopted from the Section 812 studies have received extensive review by the independent Science Advisory Board and by the public.

As described in more detail in the Draft RIA for today's proposal, this overall analytical design involves the following sequential steps:

1. Identify the *technologies* likely to be used to comply with the proposed standards
2. Estimate the *costs* society would incur to employ the technologies
3. Estimate the *emissions reductions* achieved by application of the technologies
4. Estimate the change in *air quality* conditions resulting from the estimated emissions reductions
5. Estimate the changes in *human health and well-being and environmental quality* associated with the estimated changes in air quality
6. Estimate the *economic value* of the estimated changes in human health, human welfare, and environmental outcomes
7. Compare the resulting estimate of economic benefits with the estimated costs, and calculate the *net monetized benefits* of the proposed standards
8. Evaluate the *uncertainty* surrounding the estimate of net monetized benefit by developing ranges of results that reflect the key underlying scientific, economic, data, and modeling uncertainties

c. *What Are the Significant Limitations of the Benefit-Cost Analysis?* Every BCA examining the potential effects of a change in environmental protection requirements is limited to some extent by data gaps, limitations in model capabilities (such as geographic coverage), and uncertainties in the underlying scientific and economic studies used to configure the benefit and cost models. Deficiencies in the scientific literature often result in the inability to estimate changes in health and environmental effects, such as potential increases in premature mortality associated with increased exposure to carbon models. Deficiencies in the economics literature often result in the inability to assign economic values even to those health and environmental outcomes that can be quantified, such as changes in lung function caused by increased exposure to ozone. While these general uncertainties in the underlying scientific and economics literatures are discussed in detail in the RIA and its supporting documents and references, the key uncertainties that have a bearing on the results of the preliminary BCA of today's proposed standards are:

1. The exclusion of potentially significant benefit categories (e.g., health and ecological benefits of incidentally controlled hazardous air pollutants)
2. Scientific uncertainties regarding whether the observed statistical relationship between exposure to elevated particulate matter and incidences of adverse health effects reflects a causal relationship (especially premature mortality and chronic bronchitis)
3. Scientific uncertainty regarding the potential existence of a concentration threshold below which adverse health effects of exposure to particulate matter might not occur
4. Scientific uncertainty regarding whether tropospheric ozone exposure contributes to premature mortality

In addition to these uncertainties and shortcomings that pervade all analyses of criteria air pollutant control

[71] The ''section 812 studies'' refers to (1) USEPA, Report to Congress: The Benefits and Costs of the Clean Air Act, 1970 to 1990, October 1997 (also known as the ''section 812 Retrospective); and (2) the first in the ongoing series of prospective studies estimating the total costs and benefits of the Clean Air Act, expected to be published later in 1999.

[72] Regulatory Impact Analysis for the NO_X SIP Call, FIP, and Section 126 Petitions'' September 1998, EPA–452/R–98–003.

programs, a number of limitations apply specifically to the preliminary BCA of today's proposed rules. Though we used the best data and models currently available, we were required to adopt a number of simplifying assumptions and to use data sets that, while reasonably close, did not match precisely the conditions and effects expected to result from implementation of the standards proposed today. For example, the year 2010 emissions data sets available for use in this analysis do not fully reflect the emissions reductions expected to be achieved by other recently-enacted standards and by expected near-future control programs, such as additional measures aimed at full attainment of the new fine particulate matter National Ambient Air Quality Standards. In addition, we have used the year 2010 as a proxy for the time (actually circa 2040) when all non-complying vehicles would be fully retired from the fleet and full implementation of today's proposed standards would be finally achieved, requiring adjustments described more fully in the next section. The key limitations and uncertainties unique to the preliminary BCA of today's proposed rules, therefore, include:

1. A mismatch between the 2010 air quality base year adopted for the BCA and the eventual timing of fleet turnover
2. Potential mis-estimation of future year emissions inventories, such as those associated with nonroad vehicle emissions and with measures aimed at attaining and maintaining compliance with newly revised ambient air quality standards
3. Uncertainties associated with the extrapolation of air quality monitoring data to distant sites required to capture the effects of the proposed standards on all affected populations

Despite these additional important uncertainties, which are discussed in more detail or referenced in the Draft RIA, we believe the preliminary BCA does provide a reasonable indication of the potential range of net economic benefits of the standards proposed today. This is because the analysis focuses on estimating the economic effects of the *changes* in air quality conditions expected to result from today's proposed rules, rather than focusing on developing a precise prediction of the *absolute* levels of air quality likely to prevail at some particular time in the future. An analysis focusing on the changes in air quality can give useful insights into the likely economic effects of emission reductions of the magnitude expected to result from today's proposed rule.

d. *How Did We Perform the Benefit-Cost Analysis?* As summarized above, the analytical sequence begins with a projection of the mix of technologies likely to be deployed to comply with the new standards, and the costs incurred and emissions reductions achieved by these changes in technology. The program proposed today has various cost and emission related components, as described earlier in this section. These components would begin at various times and in some cases would phase in over time. This means that during the early years of the program there would not be a consistent match between cost and benefits. This is especially true for the vehicle control portions of the proposal, where the full vehicle cost would be incurred at the time of vehicle purchase, while the fuel cost along with the emission reductions and benefits would occur throughout the lifetime of the vehicle. To deal with this question, we might have wished to perform a per-vehicle analysis corresponding to the cost effectiveness analysis described above. However, the modeling used for benefits estimates cannot be done on a per-vehicle basis, so we have instead used an annual cost and annual benefit approach.

To develop a representative benefit-cost number, we need to have a stable set of cost and emission reductions to use. This means using a future year where the fleet is fully turned over and there is a consistent annual cost and annual emission reduction. For today's proposal this stability wouldn't occur until well into the future. However, for the purpose of the benefit calculations, we have no available baseline data set beyond the year 2010. We have therefore made adjustments to allow use of 2010 as a surrogate for a future year in which the fleet consists entirely of Tier 2 vehicles.

For emissions, we calculated reductions by treating 2010 as if the fleet had already turned over. We did this by applying the control case emission factor from a fully turned over fleet year (from the year 2040) to the fleet mileages for this year. Clearly, this approach does not, nor is it intended to, predict actual expected emission reductions for 2010. This is not its purpose. It is intended to portray the characteristics of the vehicle fleet after it is fully turned over, within the constraint that 2010 was the latest year for which we could perform an analysis.

The resulting analysis represents a snapshot of benefits and costs in a future year in which the light-duty fleet consists entirely of Tier 2 vehicles. As such, it depicts the maximum emission reductions (and resultant benefits) and among the lowest costs that would be achieved in any one year by the program on a ''per mile'' basis. (Note, however, that net benefits would continue to grow over time beyond those resulting from this analysis, but only because of growth in vehicle miles traveled.) Thus, based on the long-term costs for a fully turned over fleet, the resulting benefit-cost ratio will be close to its maximum point (for those benefits that we have been able to value).

Costs to be compared to the monetized value of the benefits were also developed for a fleet the size of the year 2010 fleet. For this purpose we used the long term cost once the capital costs have been recovered and the manufacturing learning curve reductions have been realized, since this most closely represents the makeup of a fully turned over fleet.

We also made adjustments in the costs to account for the fact that there is a time difference between when some of the costs are expended and when the benefits are realized. The vehicle costs are expended when the vehicle is sold, while the fuel related costs and the benefits are distributed over the life of the vehicle. We resolved this difference by using costs distributed over time such that there is a constant cost per ton of emissions reduction and such that the net present value of these distributed costs corresponds to the net present value of the actual costs.

The resulting adjusted costs are somewhat greater than the expected actual annual cost of the program, reflecting the time value adjustment. Thus, both because of the assumption of a fully turned over fleet and because of the time value adjustment, the costs presented in this section do not represent expected actual annual costs for 2010. Rather, they represent an approximation of the steady-state cost per ton that would likely prevail in 2015 and beyond. The benefit cost ratio for the earlier years of the program would be expected to be lower than that based on these costs, since the fleet-adjusted costs are larger in the early years of the program while the benefits are smaller.

Finally, at the time that we undertook the development of the benefit estimates for this rule, we did not have quantitative estimates of the VOC emission reductions that would result from the evaporative emission standards in the proposal. Therefore, the benefit estimates do not include the value of the evaporative emission standard. Consistent with this, the program cost estimates also exclude the evaporative emission control cost. Since the evaporative emission reductions and costs are both relatively small compared to the rest of the program, they are not expected to significantly affect the overall cost-benefit ratio.

In order to estimate the changes in air quality conditions that would result from these emissions reductions, we developed two separate, year 2010 emissions inventories to be used as inputs to the air quality models. The first, baseline inventory reflects the best available approximation of the county-by-county emissions for NO_X, NMHC, and SO_2 expected to prevail in the year 2010 in the absence of the standards proposed today. To generate the second, control case inventory, we first estimated the change in vehicle emissions, by pollutant and by county, expected to be achieved by the 2010 control scenario described above. We then took the baseline emissions inventory and subtracted the estimated reduction for each county-pollutant combination to generate the second, control case emissions inventory. Taken together, the two resulting emissions inventories reflect two alternative states of the world and the differences between them represent our best estimate of the reductions in emissions that would result from our control scenario.

With these two emissions inventories in hand, the next step was to ''map'' the county-by-county and pollutant-by-pollutant emission estimates to the input grid cells of two air quality models and one deposition model. The first model, called the Urban Airshed Model (UAM), is designed to estimate the tropospheric ozone concentrations resulting from a specific inventory of emissions of ozone precursor pollutants, particularly NO_X and NMHC. The second model, called the Climatological Regional Dispersion Model Source-Receptor Matrix model (S–R Matrix), is designed to estimate the changes in ambient particulate matter and visibility that would result from a specific set of changes in emissions of primary particulate matter and secondary particulate matter precursors, such as SO_2, NO_X, and NMHC. Also, separate factors relating nitrogen emissions to watershed deposition were developed using the Regional Acid Deposition Model (RADM). By running both the baseline and control case emissions inventories through these models, we were able to estimate the expected 2010 air quality conditions and the changes in air quality conditions that would result from the emissions reductions expected to be achieved by the standards proposed today.

After developing these two sets of year 2010 air quality profiles, we used the same health and environmental effect models used in the 812 studies to calculate the differences in human health and environmental outcomes projected to occur with and without the proposed standards. Specifically, we used the Criteria Air Pollutant Modeling System (CAPMS) to estimate changes in human health outcomes, the Agricultural Simulation Model (AGSIM) to estimate changes in yields of a selected few agricultural crops, and a Household Soiling Damage function to estimate the value of reduced household soiling due to particulate matter. In addition, the benefits of reduced visibility impairment were estimated using the same overall methodology used in the 812 studies, updated to reflect recent advancements in the literature. Finally, we developed estimates of the effect of changes in nitrogen deposition to sensitive estuaries using methodologies applied in the PM/Ozone NAAQS RIA (1997) and in the recent NO_X SIP Call rulemaking. (These benefits models and methodologies are described in detail in the RIAs associated with these actions.) Several air quality-related health and environmental benefits, however, could not be calculated for the preliminary BCA of today's proposed standards. Changes in human health and environmental effects due to changes in ambient concentrations of carbon monoxide (CO), gaseous sulfur dioxide (SO_2), gaseous nitrogen dioxide (NO_2), and hazardous air pollutants could not be included, though some of these may be included in the extended analysis to be conducted for the final rule.

To characterize the total economic value of the reductions in adverse effects achieved across the lower 48 states,[73] we used the same set of economic valuation coefficients and models used in the section 812 studies and the recent NO_X SIP Call RIA to convert each type of adverse effect into a dollar value equivalent. The net monetary benefits of today's proposed standards were then calculated by subtracting the estimated costs of compliance from the estimated monetary benefits of the reductions in adverse health and environmental effects.

In the final step of the analysis, we estimated the range of net benefit estimates that might occur if important but uncertain underlying factors were allowed to vary. By conducting this ''uncertainty analysis,'' we sought to demonstrate how much the overall net benefit estimate might vary based on the particular uncertainties underlying the estimates for human health and environmental effect incidence and the economic valuation of those effects. To accomplish this, we calculated a range of possible monetized benefit estimates using two sets of assumptions surrounding the modeling techniques.

The method for presenting uncertainty, referred to here as the sensitivity approach, identifies the uncertain variables that appear to most strongly influence the overall uncertainty in the monetized benefit estimate. These included, among others, (1) The potential that a concentration threshold exists below that adverse PM-related health effects may not occur, (2) alternative methods for valuing mortality, (3) the potential contribution of tropospheric ozone to premature mortality, (4) alternative methods for valuing reduced cases of chronic bronchitis, (5) the extent to which agricultural crops included in our benefits model are resistant to damage from tropospheric ozone, (6) alternative approaches for valuing visibility. After identifying these key variables, we defined lower bound and upper bound values for each variable and combined these into a Low Case and a High Case. This approach allowed us to demonstrate the sensitivity of the total benefits to uncertainties in important variables. For example, there is no compelling scientific evidence that a PM concentration threshold exists below that adverse health effects do not occur. However, there is also no scientific evidence ruling out the potential existence of a threshold. As a result, there are no data available that would support estimating the probability that a threshold exists at any particular PM concentration. Under these circumstances, using the sensitivity approach allows us to demonstrate the effect of assuming different levels for a PM threshold.

This uncertainty calculation method does not provide a definitive or complete picture of the true range of monetized benefits estimates. This approach, as implemented in this preliminary BCA, does not reflect important uncertainties in earlier steps of the analysis, including estimation of compliance technologies and strategies, emissions reductions and costs associated with those technologies and strategies, and air quality and deposition changes achieved by those emissions reductions. Nor does this approach provide a full accounting of all potential benefits (or disbenefits) associated with the Tier 2 standards, due to data or methodological

[73] Though California is included based on the expectation that reductions in surrounding states will achieve some benefits in California, this analysis does not assume additional reductions in California emissions beyond those already achieved by prevailing standards.

limitations. Therefore, the uncertainty range is only representative of those benefits that we were able to quantify and monetize.

e. *What Were the Results of the Benefit-Cost Analysis?* The preliminary BCA for the proposed standards reflects a single year ''snapshot'' indicative of the relative yearly benefits and costs expected to be realized once the proposed standards have been fully implemented and non-compliant vehicles have all been retired. By necessity, we chose to model the year 2010 because essential data on emissions and air quality were available for this year, but not for later years, even though the complete turnover of the fleet to Tier 2 compliant vehicles will not occur until well after 2010. Consequently, these results are best viewed as a representation of yearly benefits and costs over the long-term and should not be interpreted as reflecting actual benefits and costs likely to be realized for the year 2010 itself. Benefits of the amounts shown here are likely to be realized in the 2015–2020 time frame. In reality, near-term costs will be higher than long-run costs as vehicle manufacturers and oil companies invest in new capital equipment and develop and implement new technologies. In addition, near-term benefits will be lower than long-run benefits because it will take a number of years for Tier 2-compliant vehicles to fully displace older, more polluting vehicles. However, as described earlier, we have adjusted the cost estimates upward to compensate for this discrepancy in the timing of benefits and costs and to ensure that the benefits and costs are calculated on a consistent basis. Because of this adjustment, the cost estimates also should not be interpreted as reflecting the actual costs expected to be incurred in the year 2010. Actual program costs can be found in Section IV.D.3.

Earlier in this section, we described in more detail our approach to estimating and adjusting our cost estimates, based upon the long-run costs expected to be incurred in future years after the initial capital and technology investments have been made. The resulting adjusted cost values are given in Table IV.D.–5. Since the long term costs are not representative of the per vehicle costs in the early phases of the program, we also estimated an adjusted cost based on the near term cost effectiveness value. Using the near term cost effectiveness value of $2134/per ton, the adjusted cost would be $4.3 billion. While no actual in-use fleet could consist entirely of vehicles experiencing this near term cost, this value does present an upper bound on the cost figure.

TABLE IV.D.–5.—ADJUSTED COST FOR COMPARISON TO BENEFITS

Cost basis	Adjusted cost (billions of dollars)
Long term	3.5

With respect to the benefits, several different measures of benefits can be useful to compare and contrast to the estimated compliance costs. These benefit measures include: (a) The tons of emissions reductions achieved, (b) the reductions in incidences of adverse health and environmental effects, and (c) the estimated economic value of those reduced adverse effects. Calculating the cost per ton of pollutant reduced is particularly useful for comparing the cost effectiveness of proposed new standards or programs against existing programs or alternative new programs achieving reductions in the same pollutant or combination of pollutants. The cost-effectiveness analysis presented earlier in this preamble provides such calculations on a per-vehicle basis. Considering the absolute numbers of avoided adverse health and environmental effects can also provide valuable insights into the nature of the health and environmental problem being addressed by the rule as well as the magnitude of the total public health and environmental gains potentially achieved by the proposed rule. Finally, when considered along with other important economic dimensions—including environmental justice, small business financial effects, and other outcomes related to the distribution of benefits and costs among particular groups—the direct comparison of quantified economic benefits and economic costs can provide useful insights into the overall estimated net economic effect of the proposed standards.

Table IV.D.–6 presents our range of estimates of both the estimated reductions in adverse effect incidences and the estimated economic value of those incidence reductions. Specifically, the table lists the avoided incidences of individual health and environmental effects, the pollutant associated with each of these endpoints, and the range of estimated economic value of those avoided incidences. For several effects, particularly environmental effects, direct calculation of economic value in response to air quality conditions is performed, eliminating the intermediate step of calculating incidences. Table IV.D.–7 supplements Table IV.D.–6 by listing those additional health and environmental benefits that could not be expressed in quantitative incidence and/or economic value terms. A full appreciation of the overall economic consequences of today's proposed standards requires consideration of all benefits and costs expected to result from the new standards, not just those benefits and costs that could be expressed here in dollar terms.

TABLE IV.D.–6.—AVOIDED INCIDENCE AND MONETIZED BENEFITS ASSOCIATED WITH THE TIER 2 RULE FOR A RANGE OF ASSUMPTION SETS

Endpoint	Avoided incidence (cases/year)		Monetary benefits (millions 1997$)	
	Low [a]	High [b]	Low	High
PM:				
Mortality (long-term exp.—ages 30+)	832	2,416	2,275	14,256
Mortality (long-term exp.—infants)	....	10	....	56
Chronic bronchitis	3,885	3,914	281	1,354
Hosp. Admissions—all respiratory (all ages)	504	836	4.6	7.6
Hosp. Admissions—congestive heart failure	127	138	1.5	1.7
Hosp. Admissions—ischemic heart disease	146	159	2.2	2.4
Acute bronchitis	984	4,072	0.1	0.2
Lower respiratory symptoms (LRS)	19,782	37,437	0.3	0.5
Upper respiratory symptoms (URS)	3,093	3,387	0.1	0.1
Work loss days (WLD)	233,000	415,000	23.8	42.3
Minor restricted activity days (MRAD)	1,856,000	3,370,000	87.7	159.3

TABLE IV.D.–6.—AVOIDED INCIDENCE AND MONETIZED BENEFITS ASSOCIATED WITH THE TIER 2 RULE FOR A RANGE OF ASSUMPTION SETS—Continued

Endpoint	Avoided incidence (cases/year)		Monetary benefits (millions 1997$)	
	Low [a]	High [b]	Low	High
Household soiling damage			60.1	60.1
Ozone:				
Mortality (short-term; four U.S. studies)		388		2,312
Hospital admissions—all respiratory (all ages)	549	736	5.3	7.1
Any of 19 acute symptoms	54,101	71,545	1.3	1.7
Decreased worker productivity			43.0	60.4
Agricultural crop damage			−1	301
Visibility			165	701
Nitrogen Deposition			200	200
Total (PM + ozone + visibility + N deposition)			3,150	19,525

[a] The low assumption set assumes effects from PM do not occur below concentrations of 15 μg/m^3, that all mortality and chornic bronchitis effects occur within the same year of the PM reduction (see Section 7.a. of the Draft RIA for a discussion of this uncertainty), utilizes the value of statistical life year lost approach, ozone-related mortality and PM-related infant mortality are not included in the benefits estimate, chronic bronchitis valued with the cost of illness approach, plantings of commodity crop cultivars are assumed to be insensitive to ozone, does not value residential visibility benefits, and uses the lower-bound estimate of ''willingness to pay'' for recreational visibility to reflect variation.

[b] The high assumption set assumes a PM threshold of background, utilizes the value of a statistical life approach, both ozone-related mortality and PM-related mortality are included in the estimation of benefits, chronic bronchitis valued with a willingness-to-pay approach, plantings of commodity crop cultivars are assumed to be sensitive to ozone, and full accounting for recreational and residential visibility benefits.

TABLE IV.D.–7.—ADDITIONAL, NON-MONETIZED BENEFITS OF PROPOSED TIER 2 STANDARDS

Pollutant	Nonmonetized adverse effects
Particulate Matter	Large Changes in Pulmonary Function.
	Other Chronic Respiratory Diseases.
	Inflammation of the Lung.
	Chronic Asthma and Bronchitis.
Ozone	Changes in Pulmonary Function.
	Increased Airway Responsiveness to Stimuli.
	Centroacinar Fibrosis.
	Immunological Changes.
	Chronic Respiratory Diseases.
	Extrapulmonary Effects (i.e., other organ systems).
	Forest and other Ecological Effects.
	Materials Damage.
Carbon Monoxide	Premature Mortality.
	Decreased Time to Onset of Angina.
	Behavioral Effects.
	Other Cardiovascular Effects.
	Developmental Effects.
Sulfur Dioxide	Respiratory Symptoms in Non-Asthmatics.
	Hospital Admissions.
	Agricultural Effects.
	Materials Damage.
Nitrogen Oxides	Increased Airway Responsiveness to Stimuli.
	Decreased Pulmonary Function.
	Inflammation of the Lung.
	Immunological Changes.
	Eye Irritation.
	Materials Damage.
	Acid Deposition.
Hazardous Air Pollutants	All Human Health Effects.
	Ecological Effects.

These results indicate that, based on the particular assumptions, models, and data used in this preliminary BCA, the range of monetary benefits realized after full turnover of the fleet to Tier 2 vehicles would be approximately 3.2 billion to 19.5 billion dollars per year. Comparing this estimate of the economic benefits with the adjusted cost estimate indicates that the net economic benefit of the proposed standards to society could be from a net cost of 0.4 billion to a net benefit of 16.0 billion dollars per year.

The breadth of the ranges of net economic benefit estimates presented in this preliminary BCA reinforces our conclusion that these BCA results may be indicative of potential overall economic effects, but they should by no means dictate whether or not the standards proposed today should be promulgated.

f. *What Additional Efforts Will Be Made Following Proposal?* While we believe that the preliminary BCA provides a strong indication that the standards proposed today will yield positive overall economic benefits, we believe it is important to do additional analysis prior to the final decision regarding these standards. In particular, we plan to develop an updated and extended set of emissions inventories, and to expand the range of pollutant-specific effects to include the benefits of reductions in carbon monoxide (CO), sulfur dioxide (SO_2), nitrogen dioxide (NO_2), and perhaps hazardous air pollutants. We will also carefully review the public comments submitted on the preliminary BCA and review each of the assumptions and methods used in light these public comments and the advice of the Science Advisory Board charged with reviewing these and other methods being used in the pending section 812 Prospective Study Report to Congress.

E. Other Program Design Options We Have Considered

In addition to the proposed program combining Tier 2 vehicle standards and gasoline sulfur controls, we have considered two other major alternatives to a comprehensive vehicle/fuel program. This section identifies these two alternatives and seeks comment on specific aspects of each.

1. Corporate Average Standards Based on NMOG or NMOG+NO_X

We have described in great detail in previous sections of this preamble why NO_X is our main pollutant of concern for this rulemaking. Based on this conclusion, we are proposing a Tier 2 program that is centered around a full useful life corporate average NO_X standard (0.07 g/mi). Our proposed interim program for non-Tier 2 vehicles is also centered around a corporate average NO_X standard (0.30 or 0.20 g/mi, depending on vehicle type).

California's program, by contrast, is centered on corporate average NMOG standards. We recognize that for Tier 2 vehicles we could also set up the bins of emission standards and impose an average NMOG standard in a similar fashion. A program centered on corporate average NMOG standards could even be defined in such a way that NO_X emissions would be indirectly driven down to the levels we have defined with our proposed Tier 2 standards. Such an approach would provide more consistency with California's program, and would be consistent with our own NLEV program. However, we believe it is best, for the federal program, to use a NO_X average standard.

With a NO_X average standard we can better tailor the various aspects of the program to reduce the pollutant with which we are most concerned. Thus, our averaging, banking and trading program has been set up to provide NO_X credits for early compliance with the Tier 2 NO_X average standard and to provide additional NO_X credits for manufacturers certifying to extended useful lives. Also, the NO_X average standard allows us to set up bins in such a way as to provide manufacturers with incentives to strive for additional NO_X reductions.

Although the use of an average NO_X requirement conflicts with California's requirements, we do not believe any additional burden is imposed on manufacturers. Under an NMOG averaging requirement, manufacturers would still have to compute separate NMOG averages for their California and Federal vehicles. This would be no smaller burden than computing an NMOG average for California vehicles and a NO_X average for Federal vehicles. We request comment on the appropriateness and burden of our NO_X averaging standards and on what benefits, if any, might be afforded by an NMOG standard for the federal program in lieu of the proposed NO_X average.

2. More Stringent Tier 2 NO_X and Gasoline Sulfur Standards

We considered whether average NO_X levels even lower than 0.07 g/mi (which would likely result in lower NO_X standards for all of the Tier 2 certification bins and substantially limit the number of vehicles certified at NO_X emissions levels significantly higher than 0.07 g/mi) might be possible and cost effective in a scenario where sulfur levels in gasoline would be reduced to an average level on the order of 10 ppm (with perhaps a 20 ppm cap). Manufacturers have requested that California consider such a ''near zero'' sulfur limit to help them to meet the mandatory bins in the CAL LEV II program, which are more stringent than what would be required in the proposed Tier 2 program. We believe our proposed Tier 2 standards can be met with the proposed gasoline sulfur standards. However, tighter Tier 2 standards could require even lower gasoline sulfur limits.

We selected our proposed Tier 2 standards and gasoline sulfur levels based on air quality need, technical feasibility, and cost effectiveness. Hence, we believe the proposed requirements are reasonable and are as stringent as is warranted. However, in consideration of the alternative discussed here, we request comment on the ability of manufacturers to produce vehicles meeting a corporate average NO_X emission level substantially lower than 0.07 g/mi. How would the cost of producing such a vehicle differ from the costs estimated for the proposed Tier 2 vehicles? How sensitive would such a vehicle be to the sulfur level of gasoline, and what sulfur level would be required? How soon could manufacturers be expected to be able to comply with a lower NO_X standard, given that they will be producing LEVII vehicles for California beginning in 2004?

We also request comment on the magnitude of additional sulfur reduction that would be necessary to reduce average full useful life NO_X to levels significantly below 0.07 g/mi, and whether such low levels of sulfur can be met with the technology EPA expects refiners to use to meet the requirements we are proposing today. We request comment on the costs of such sulfur reductions and the timing needed to acquire and implement any additional refinery controls. If refiners invest today to achieve 30 ppm average sulfur levels, will those investments be rendered obsolete by a future sulfur requirement of a near-zero average, or would the technologies complement one another? How much time would refiners need to comply with a near-zero sulfur standard following compliance with a 30 ppm standard?

V. Additional Elements of the Proposed Vehicle Program and Areas for Comment

The section describes several additional provisions of the vehicle proposal and issues on which we are requesting comment that were not previously discussed in this preamble.

A. Other Vehicle-Related Elements of the Proposal

1. Proposed Tier 2 CO, HCHO and PM Standards

Table IV.B.–1 in Section IV.B.4.a. above presented the proposed Tier 2 standards for carbon monoxide (CO), formaldehyde (HCHO), and particulate matter (PM). The following paragraphs discuss our selection of these specific standards for proposal.

a. *Carbon Monoxide (CO) Standards.* Beyond aligning carbon monoxide (CO) standards for all LDVs and LDTs, and allowing harmonizing with California vehicle technology, reduction in CO emissions is not a primary goal of the Tier 2 program. Thus the CO standards we are proposing for all Tier 2 LDVs and LDTs are essentially the same as those from the NLEV program for LDVs and LDT1s. These standards would harmonize with CalLEV II CO standards except at California's SULEV level (EPA Bin 2). This lone divergence would not pose additional burden to manufacturers because the proposed federal Tier 2 CO standards for these vehicles would be less stringent than California's. Our proposed interim standards during the phase-in of Tier 2 standards would apply these same CO standards.

As we indicated in the Tier 2 Report to Congress, the number and severity of CO NAAQS violations have decreased greatly in recent years. Presently, CO exceedances occur primarily during cold weather. The need for more stringent cold CO standards is a subject of a separate EPA study that is now underway. Consequently, in this rulemaking we propose to simply align CO standards for all categories with those applicable to LDVs and LDT1s under NLEV. This alignment is consistent with our goal of bringing all LDVs and all categories of LDTs under common standards that allow for technology to be harmonized to the extent possible with California.

We believe that technological changes to bring LDT2s and HLDTs [74] under tighter NMOG standards should easily ensure compliance with the CO standards at no additional cost. In fact, certification data on current model year LDTs indicate that there are LDTs in all categories that can already meet the LDV/LDT1 NLEV CO standard.

We recognize that the vast majority of CO emissions are from motor vehicles and that increases in population in some areas combined with increases in vehicle miles traveled could lead to additional incidences of CO nonattainment. Consequently, we request comment on the need for and implications of tighter CO standards for any category of vehicles affected by today's document.

b. *Formaldehyde (HCHO) Standards.* Similar to our approach to the proposed CO standards, we are proposing to align all Tier 2 LDVs and LDTs under the formaldehyde standards for LDVs and LDT1s from the NLEV program. For new bins below Bin No. 4, we propose to adopt the CalLEV II standards for formaldehyde. HLDTs, which are not subject to the NLEV program, would become subject to HCHO standards for the first time under the provisions of this rulemaking. The Tier 2 formaldehyde standards would be essentially replicated in the interim standards we are proposing for LDVs and LDTs.

Formaldehyde is a component of NMOG but is primarily of concern for methanol-fueled vehicles, because it is chemically similar to methanol and is likely to occur when methanol is not completely burned in the engine. HLDTs are not included under the NLEV program and will therefore not face formaldehyde standards as LDVs and LLDTs will in 2001 (1999 in the northeast states). We believe it is appropriate to bring HLDTs under HCHO standards in this rulemaking. Applying formaldehyde standards to HLDTs would be consistent with our goals of aligning standards for all LDVs and LDTs regardless of fuel type and harmonizing technologically with California standards wherever possible and reasonable and the burden would be minimal.

Consequently, we are proposing to include formaldehyde standards for HLDTs under the Tier 2 program as well as under the interim programs. We note that HCHO is actually a component of NMOG, and as with CO, we expect that all vehicles able to meet the Tier 2 or interim NMOG standards (including methanol-fueled vehicles) would readily comply with the HCHO standards.

c. *Particulate Matter (PM) Standards.* We are proposing to adopt tighter PM standards, although in this case only full useful-life standards. For Tier 2 vehicles, we are proposing a 0.01 g/mi standard for all categories at the Tier 2 (Bin 5) level or below (except ZEV which, of course, is 0.0). To provide manufacturers with additional flexibility, we are proposing a 0.02 g/mi PM standard for vehicles that certify to Bins 6 or 7 standards.

For non-Tier 2 LDV/LLDTs during the phase-in period, we are proposing a PM standard of 0.06 g/mi for Bins 4 and 5. The other standards would be 0.04 for Bin 3 and 0.01 for Bin 2. For non-Tier 2 HLDTs, similar standards would apply except that the highest bin would have a PM standard of 0.06 g/mi, gradually decreasing in the other bins to 0.01 g/mi (Bin 2).

PM standards are primarily a concern for diesel-cycle vehicles, but they also apply to gasoline and other otto-cycle vehicles. We propose to continue to permit otto-cycle vehicles to certify to PM standards based on representative test data from similar technology vehicles. We request comment on the degree to which these standards would affect the certification of diesel-fueled vehicles.

2. Useful Life

The ''useful life'' of a vehicle is the period of time, in terms of years and miles, during which a manufacturer is formally responsible for the vehicle's emissions performance. For LDVs and LDTs, there have historically been both ''full useful life'' values, approximating the average life of the vehicle on the road, and ''intermediate useful life'' values, representing about half of the vehicle's life. We are proposing several changes to the current useful life provisions for LDVs and LDTs.

a. *Mandatory 120,000 Mile Useful Life.* We are today proposing to equalize full useful life values for all 2004 and later model year LDVs and LDTs at 120,000 miles. This value would apply to Tier 2 and interim non-Tier 2 vehicles. California, in its LEV II program, has adopted full useful life standards for all LDVs and LDTs of 10 years or 120,000 miles, whichever occurs first. We are proposing that the time period for federal LDV/LLDTs would be 10 years, but it would remain at 11 years for HLDTs consistent with the Clean Air Act.[75] Intermediate useful life values, where applicable, would remain at 5 years or 50,000 miles, whichever occurs first. Where manufacturers elect to certify Tier 2 vehicles for 150,000 miles to gain additional NO_X credits, as discussed below, the useful life of those vehicles would be 15 years and 150,000 miles. We are not proposing to harmonize with California on the mandatory useful life for evaporative emissions of 15 years and 150,000 miles, but rather we are proposing that this useful life be mandatory for evaporative emissions only when a manufacturer elects optional 150,000 mile exhaust emission certification.

b. *150,000 Mile Useful Life Certification Option.* We are proposing to adopt a provision to provide additional NO_X credit in the fleet average calculation for vehicles certified to a useful life of 150,000 miles. In our proposal, a manufacturer certifying an engine family to a 150,000 mile useful life would incorporate those vehicles into its corporate NO_X average as if they were certified to a full useful life standard 0.85 times the applicable 120,000 mile NO_X standard. To use this option, the manufacturer would have to agree to (1) certify the engine family to the applicable 120,000 mile exhaust and evaporative standards at 150,000 miles for all pollutants; and (2) increase the mileage on the single extra-high mileage in-use test vehicle from a minimum of

[74] As defined earlier, the category called HLDT, or heavy light-duty truck, includes all LDTs greater than 6000 pounds GVWR. This term includes the categories LDT3 and LDT4.

[75] Section 202(h) of the Clean Air Act specifies a useful life of 11 years/120,000 miles for HLDTs. California is able to use a 10 year figure because it has a waiver under section 209 of the Act to implement its own emission control program when such program is found to be at least as protective of public health and welfare ''in the aggregate'' as the federal program.

90,000 miles to a minimum of 105,000 miles.

Congress, in directing EPA to perform the Tier 2 study, also directed EPA to consider changing the useful lives of LDVs and LDTs. Manufacturers have made numerous advances in quality, materials and engineering that have led to longer actual vehicle lives and data show that each year of a vehicle's life, people are driving more miles. Current data indicate that passenger cars are driven approximately 120,000 miles in their first ten years of life. Trucks are driven approximately 150,000 miles. Current regulatory useful lives are 10 years/100,000 miles for LDV/LLDTs and 11 years/120,000 miles for HLDTs. We project based on our Tier 2 model that approximately 13 percent of light-duty NO_X and 11 percent of light-duty VOCs is produced between 100,000 and 120,000 miles. Given the trend toward longer actual vehicle lives and increases in annual mileage, we believe that it is reasonable to propose extension to the regulatory useful life requirements.

Additionally, 41 percent of light-duty NO_X and 59 percent of light-duty VOC is produced beyond 120,000 miles. Based on this data, we believe it is also appropriate to propose incentives to manufacturers to certify their vehicles to extended useful lives beyond 120,000 miles. This is why we are proposing, as discussed above, to provide additional NO_X credits for Tier 2 vehicles certified to a useful life of 150,000 miles.

3. Light Duty Supplemental Federal Test Procedure (SFTP) Standards

Supplemental Federal Test Procedure (SFTP) standards require manufacturers to control emissions from vehicles when operated at high rates of speed and acceleration (the US06 test cycle) and when operated under high ambient temperatures with air conditioning loads (the SC03 test cycle). The existing light duty SFTP requirements begin a three year phase-in in model year 2000 for Tier 1 LDV/LLDTs . For HLDTs, SFTP requirements begin a similar phase-in in 2002. Intermediate and full useful life standards exist for all categories. SFTP standards do not apply to diesel fueled Tier 1 LDT2s and HLDTs. Table V.A.–1 shows the full useful life federal SFTP requirements applicable to Tier 1 vehicles.

TABLE V.A.–1.—FULL USEFUL LIFE FEDERAL SFTP STANDARDS APPLICABLE TO TIER 1 VEHICLES

Vehicle category	$NMHC + NO_X$ (weighted g/mi) [a]	CO (g/mi) [b]		
		US06	SC03	Weighted
LDV/LDT1 (gasoline)	0.91	11.1	3.7	4.2
LDV/LDT1 (diesel)	2.07	11.1	....	4.2
LDT2	1.37	14.6	5.6	5.5
LDT3	1.44	16.9	6.4	6.4
LDT4	2.09	19.3	7.3	7.3

[a] Weighting for $NMHC+NO_X$ and optional weighting for CO is 0.35×(FTP)+0.28×(US06)+0.37×(SC03).
[b] CO standards are stand alone for US06 and SC03 with option for a weighted standard.

The NLEV program includes SFTP requirements for LDVs, LDT1s and LDT2s. These requirements impose the Tier 1 intermediate and full useful life SFTP standards on Tier 1 and TLEV vehicles, but impose only 4000 mile standards on LEVs and ULEVs.[76] NLEV SFTP standards for LEVs and ULEVs are shown in Table V.A.–2. These standards do not provide for a weighted standard for $NMHC+NO_X$ or for CO, but rather employ separate sets of standards for the US06 and SC03 tests. Also, while the NLEV SFTP standards apply to gasoline and diesel vehicles, they do not include a standard for diesel particulates (PM).

TABLE V.A.–2.—SFTP STANDARDS FOR LEVS AND ULEVS IN THE NLEV PROGRAM

	US06		SC03	
	$NMHC+NO_X$ (g/mi)	CO (g/mi)	$NMHC+NO_X$ (g/mi)	CO (g/mi)
LDV/LDT1	0.14	8.0	0.20	2.7
LDT2	0.25	10.5	0.27	3.5

Since no significant numbers of vehicles certified to SFTP standards below TLEV levels will enter the fleet until 2001, manufacturers have raised concerns regarding significant changes to the SFTP program before its implementation. At this point, it seems reasonable not to increase SFTP stringency for the Tier 2 program, but we are proposing to substitute SFTP standards adjusted for intermediate and full useful life deterioration where there are currently only 4000 mile standards.

Full useful life standards for Tier 2 vehicles are consistent with our mandate under the Clean Air Act. The 4000 mile standards exist in the federal program only because they were adopted in the NLEV program—a voluntary program under which California requirements were adopted nationwide. We derived the full and intermediate useful life standards by applying deterioration allowances proposed for our MOBILE 6 model to the existing 4000 mile standards for LDVs and LLDTs. For HLDTs we applied similarly derived deterioration allowances to California's LEV I SFTP standards for MDV2s and MDV3s, which are the corresponding categories to LDT3s and LDT4s in the California program. The full and intermediate useful life SFTP standards we are proposing are shown in Tables V.A.–3

[76] This disparity in useful lives arose because neither EPA nor CARB had full useful life SFTP standards for LEVs or ULEVs when the NLEV program was adopted. Since a major requirement of the NLEV program was harmony with California standards, EPA adopted the California SFTP standards in place for the NLEV time frame (2001 and later).

and V.A.–4. These standards would apply to all Tier 2 vehicles including Tier 2 LDT3s and LDT4s.

TABLE V.A.–3.—PROPOSED FULL USEFUL LIFE SUPPLEMENTAL EMISSION STANDARDS

[(SFTP Standards (grams/mile)]

	USO6 NMHC+NO_X	USO6 CO	SCO3 NMHC+NO_X	SCO3 CO
LDV/LDT1	0.2	11.1	0.26	4.2
LDT2	0.37	14.6	0.39	5.5
LDT3	0.53	16.9	0.44	6.4
LDT4	0.78	19.3	0.62	7.3

TABLE V.A.–4.—PROPOSED INTERMEDIATE USEFUL LIFE SUPPLEMENTAL EMISSION STANDARDS

[(SFTP Standards)(grams/mile)]

	USO6 NMHC+NO_X	USO6 CO	SCO3 NMHC+NO_X	SCO3 CO
LDV/LDT1	0.16	9.0	0.22	3.0
LDT2	0.30	11.6	0.32	3.9
LDT3	0.45	11.6	0.36	3.9
LDT4	0.67	13.2	0.51	4.4

Because our proposed interim standards for LDV/LLDTs (see section VI.A.3.d. above) are derived from NLEV standards, we believe that the SFTP standards we are proposing for Tier 2 vehicles should also apply to the interim non-Tier 2 LDV/LLDTs. However, we propose that TLEV vehicles (EPA interim Bin 5 in Table IV.B.–6), which are not subject to new SFTP standards under NLEV, could continue to meet Tier 1 SFTP standards, and HLDTs under the interim programs could continue to meet Tier 1 SFTP standards that do not fully phase in until the 2004 model year.

LDT3 and LDT4 SFTP standards do not currently apply to diesels. Further, the standards applicable to Tier 1 diesel LDVs and LDT1s are less stringent than gasoline standards and do not apply to the SC03 cycle. We are proposing to apply the approach we are using with other standards in this document to the Tier 2 and interim SFTP standards. Consequently, we are proposing that Tier 2 and interim LDVs and LDTs with diesel or gasoline engines comply with the same NMHC+NO_X and CO SFTP limits. We are also requesting comment on the appropriate SFTP PM standards for diesel vehicles. We believe it would be appropriate to establish a margin between 10% and 50% above the applicable FTP PM standard to serve as the SFTP standard. As an example of how EPA has recently used such a margin, in recent consent decrees, heavy-duty engine manufacturers have agreed not to exceed emission levels 1.25 times the applicable exhaust standards (including PM standards) when engines are operated over a wide range of operating conditions. We request comment on the appropriate standard for PM in the SFTP.

4. LDT Test Weight

Historically, HLDTs (LDT3s and LDT4s) have been emission tested at their adjusted loaded vehicle weight (ALVW), while LDVs, LDT1s, and LDT2s have been tested at their loaded vehicle weight (LVW). ALVW is equivalent to the curb weight of the truck plus half its maximum payload, while LVW is equivalent to the curb weight of the truck plus a driver and one adult passenger (300 pounds). As we are proposing in this document to equalize standards and useful lives across LDVs and all categories of LDTs, we believe it is appropriate to test all the vehicles under the same conditions. Therefore, consistent with the CalLEV II program, we are proposing to test HLDTs at their loaded vehicle weight. We recognize that removing all but 300 pounds of load from these trucks during the test provides them with a somewhat ‘‘easier’’ test cycle than they currently have. However, the standards we are proposing for HLDTs under Tier 2, are considerably more stringent than the Tier 1 standards. Further, one of our reasons for bringing HLDTs under the same standards as passenger cars is that these trucks include many vans and sport utility vehicles that are often used as passenger cars with just one or two passengers. Consequently, we believe it is appropriate to test them at LVW.

5. Test Fuels

As discussed elsewhere in this preamble, the NLEV program was adopted virtually in its entirety from California's program. Because California's standards were developed around the use of California Phase II reformulated gasoline (RFG) as the exhaust emission test fuel, we adopted California Phase II test fuel as the exhaust emission test fuel for gasoline-fueled vehicles in the federal NLEV program, although we recognized at the time that vehicles outside of California would be unlikely to operate on that fuel in use.

We believe that it is best to establish compliance with standards based on the fuel that the vehicles will operate upon. However, we also believe that the major exhaust emission related issues between California Phase II fuel and federal test fuel are related to sulfur and we do not believe the other differences between the two fuels will significantly impact NMOG, CO or NO_X exhaust emissions in Tier 2 (or interim) gasoline fueled vehicles.

In this document, we are proposing to reduce the sulfur in federal test fuel to reflect the reductions in sulfur we are proposing for commercial gasoline. Currently, federal test gasoline is subject to a limit of 0.10 percent by weight. We are proposing to amend that to an allowable range of 30 to 80 ppm (0.003 to 0.008 percent by weight). We also propose that vehicles be certified and in-use tested using federal test fuel. However, where vehicles are certified for 50 state sale, and where other testing issues do not arise, we are proposing to accept the results of testing done for California certification on California Phase II fuel. We would reserve the right to perform or require in-use testing on federal fuel. Where vehicles are only certified for non-California sale, we propose to require certification and in-use testing on federal fuel. We request comments with supporting emission data on all aspects of these two possible test fuels.

Because differences exist between the California and federal evaporative emission testing procedures, we propose to continue to require the use of federal certification fuel as the test fuel in evaporative emission testing. Under current programs, where California and federal evaporative emission standards are nearly identical, California accepts evaporative results generated on the federal procedure (using federal test fuel), because available data indicates the federal procedure to be a ''worst case'' procedure. The evaporative standards California has adopted for their LEV II program are more stringent than those we are proposing in this document. We request comment and supporting emission test data on whether vehicles certified to CalLEV II evaporative standards using California fuels will necessarily comply with the federal Tier 2 evaporative standards, including ORVR standards, when tested with federal test fuel.

6. Changes to Evaporative Certification Procedures to Address Impacts of Alcohol Fuels

Current certification procedures, including regulations under the CAP2000 program,[77] allow manufacturers to develop their own durability process for calculating deterioration factors for evaporative emissions. The regulations (§ 86.1824–01) permit manufacturers to develop service accumulation (aging) methods based on ''good engineering judgement'', subject to review and approval by EPA. The manufacturer's durability process must be designed to predict the expected evaporative emission deterioration of in-use vehicles over their full useful lives. We are proposing to require that these aging methods include the use of alcohol fuels to address concerns that alcohol fuels increase the permeability and thus the evaporative losses from hoses and other evaporative components.

We have reviewed data indicating that the permeability, and therefore the evaporative losses, of hoses and other evaporative components can be greatly increased by exposure to fuels containing alcohols.[78] Alcohols have been shown to promote the passage of hydrocarbons through a variety of different materials commonly used in evaporative emission systems. Data from component and fuel line suppliers indicate that alcohols cause many elastomeric materials to swell, which opens up pathways for hydrocarbon permeation and also can lead to distortion and tearing of components like ''O'' ring seals. Ethers such as MTBE and ETBE have a much smaller effect. Alcohol-resistant materials such as fluoroelastomers are available and are currently used by manufacturers to varying extents.

Alcohols do not impact evaporative components and hoses immediately, but rather it may take as long as one year of exposure to alcohol fuels for permeation rates to stabilize. The end result in higher permeation and increased in-use evaporative emissions.[79]

Today, roughly 10% of fuel sold in the U.S. contains alcohol, mainly in the form of ethanol, and such fuels are often offered in ozone nonattainment areas. We believe it is appropriate to ensure that evaporative certification processes expose evaporative components to alcohols and do so long enough to stabilize their permeability. Therefore, we are proposing to amend evaporative certification requirements to require manufacturers to develop their deterioration factors using a fuel that contains the highest legal quantity of ethanol available in the U.S.

To implement this change, we are proposing to modify the Durability Demonstration Procedures for Evaporative Emissions found at § 86.1824–01. Our proposal would require manufacturers to age their systems using a fuel containing the maximum concentration of alcohols allowed by EPA in the fuel on which the vehicle is intended to operate, i.e., a ''worst case'' test fuel. (Under current requirements, this fuel would be about 10% ethanol, by volume.) We are also proposing to modify the Durability Demonstration Procedures to require manufacturers to ensure that their aging procedures are of sufficient duration to stabilize the permeability of the fuel and evaporative system materials.

It is our desire to find an alternative way by which a manufacturer could document or demonstrate that its tanks, hoses, connectors and other evaporative components are made of materials whose permeability is not significantly affected by alcohols. Successful manufacturers would not have to use alcohol fuel in certification. There are a variety of test methods to evaluate permeation losses from materials, components or subassemblies described in the literature.[80] However, from our discussions with component and materials suppliers, we conclude that there is currently no consensus test procedure or standard available that we could rely on to establish whether a fuel/evaporative system is likely to be sufficiently impermeable to alcohol fuels. We request comment on the availability and appropriateness of such procedures and standards and we request comment on the need for and benefits of certification enhancements to account for the effects of alcohols in fuels. We also seek comment on whether certification test fuel for evaporative emissions should include 10% ethanol.

7. Other Test Procedure Issues

California's LEV II program implements a number of minor changes to exhaust emissions test procedures. We have evaluated these changes and found that, for tailpipe emissions, the California test procedures fall within ranges and specifications permitted under the Federal Test Procedure.

With regard to HEVs and ZEVs, we believe that these vehicles will be predominantly available in California, or that they will typically be first offered for sale in California, because of California's ZEV requirement, which promotes the sale of HEVs and ZEVs. Where manufacturers market HEVs or ZEVs outside of California, it is likely that they will market the same vehicles in California. Consequently, we intend to incorporate by reference California's exhaust emission test procedures for HEVs and ZEVs.[81] We request comment on the appropriateness of this proposed incorporation and an emission allowance for HEVs.

In the NLEV program, we provided a specific formula used by California that could be used to compute an HEV contribution factor to NMOG emissions. This formula took into consideration the

[77] The Compliance Assurance Program, CAP2000, was proposed in an NPRM (63 FR 39654, July 23, 1998). The final rule was signed on March 15, 1998. As today's NPRM went forward for signature, the CAP2000 final rule had not been published, so no citation for the final rule is available. You should check our web site (http://www.epa.gov/omswww/) for the most current information on publication of the CAP2000 rule takes effect in the 2000 model year.

[78] Numerous SAE papers examine the permeability of fuel and evaporative system materials as well as the influence of alcohols on permeability. See, for example SAE Paper #s 910104, 920163, 930992, 970307, 970309, 930992, and 981360, copies of which are in the docket for this rulemaking.

[79] *Ibid.*

[80] *Ibid.*

[81] California Zero-Emission and Hybrid Electric Vehicle Exhaust Emission Standards and Test Procedures for 2003 and Subsequent Model Year Passenger Cars, Light-Duty Trucks and Medium-Duty Vehicles. September 18, 1998 for the Board Hearing of November 5, 1998.

range without engine operation of various types of HEVs and had the effect of reducing the NMOG emission standard for a given emission bin (for HEV vehicles only). This would have obvious beneficial effects on a manufacturer's calculation of its corporate NMOG average.

The technology of HEVs is under rapid change and we do not believe that we can design a formula now that will accurately predict the impact of HEVs on corporate average NO_X emissions in the Tier 2 time frame. Consequently, we are including a provision by which manufacturers could propose HEV contribution factors for NO_X to EPA. If approved, these factors could be used in the calculation of a manufacturer's fleet average NO_X emissions and would provide a mechanism to credit an HEV for operating with no emissions over some portion of its life.

These factors would be based on good engineering judgement and would consider such vehicle parameters as vehicle weight, the portion of the time during the test procedure that the vehicle operates with zero emissions, the zero emission range of the vehicle, NO_X emissions from fuel-fired heaters and any measurable NO_X emissions from on-board electricity production and storage.

The final NLEV rule (*See* 62 FR pg 31219, June 6, 1997) incorporates by reference California's NMOG measurement procedure and adopts California's approach of using Reactivity Adjustment Factors (RAFs) to adjust vehicle emission test results to reflect differences in the impact on ozone formation between an alternative-fueled vehicle and a vehicle fueled with conventional gasoline. While we intend to bring all LDVs and LDTs under NMOG standards beginning in 2004 and while we desire to harmonize with California when practical and reasonable, we are not proposing to allow the use of RAFs for Tier 2 vehicles and interim non-Tier 2 vehicles. As has been discussed elsewhere in this preamble, the NLEV program is a special case in which California standards and provisions were adopted virtually in their entirety. In the preamble to the final NLEV rule (*See* 62 FR 31203), we expressed our reservations about the use of RAFs. We also addressed our reservations about the use of reactivity factors developed in California in a program that spans a range of climate and geographic locations across the United States in the final rule on reformulated gasoline (RFG) (see 59 FR 7220). We are concerned about the validity of RAFs to predict ozone formation nationwide and have asked the National Academy of Sciences to look at the scientific evidence in support of the use of these factors nationwide. We expect to receive their report prior to making our final decisions about the Tier 2 standards.

Recognizing that we are not proposing a corporate average NMOG standard, and that RAFs impact only the calculation of NMOG emissions, we request comment on all aspects of RAFs including the impact of not using them on the severity of our proposed standards, their validity to predict ozone formation nationwide, and any impact the lack of RAFs may have on alternative fueled vehicles.

In its LEV II program, California is also implementing a number of changes to evaporative emission test procedures.[82] Many of these changes address the evaporative emission testing of hybrid electric vehicles. We are generally not proposing to adopt California's changes, because California uses different test temperatures and different test fuel in its evaporative emission testing of gasoline vehicles than we use in the federal program. The preamble to the final NLEV rule (*See* 62 FR 31227) explains that California and EPA are reviewing an industry proposal to streamline and reconcile the California and federal procedures. That work has not been completed. However, where California proposes procedures specific to HEVs and ZEVs, we do intend to adopt those procedures, except that our testing would occur at lower temperatures, and use a fuel determined by EPA to be representative of federal usage (for HEVs only). Given the small number of HEVs and ZEVs likely to be sold in states other than California early in the Tier 2 program, and given the small quantities of fuel likely to be used by HEVs in any event, we request comment on the appropriateness of simply accepting California evaporative results for HEVs and ZEVs to show compliance with the less stringent federal evaporative standards. We also request comment on whether any or all of the changes California has adopted for evaporative emission testing should be adopted into federal testing requirements.

8. Small Volume Manufacturers

Our proposal includes the following flexibilities intended to assist all manufacturers in complying with the stringent proposed standards without harm to the program's environmental goals: (1) A four year phase-in of the standards for LDV/LLDTs; (2) a delayed phase-in for HLDTs; (3) the freedom to select from specific bins of standards; (4) a standard that can be met through averaging, banking and trading of NO_X credits; (5) provisions for NO_X credit deficit carryover; and (6) provisions by which a manufacturer may generate additional NO_X credits.

These flexibilities would apply to all manufacturers, regardless of size, and in general we believe they eliminate the need for more specific provisions for small volume manufacturers. However, we are proposing one additional flexibility for small volume manufacturers.[83] Our proposal would exempt small volume manufacturers from the 25%, 50% and 75% Tier 2 phase-in requirements applicable to the 2004, 2005 and 2006 LDV/LLDTs and the 50% phase-in requirement applicable to 2008 HLDTs. Instead, small volume manufacturers would simply comply with the appropriate 100% requirement in the 2007 or 2009 model year. Our proposal would also exempt small volume manufacturers from the 25%, 50% and 75% phase-in requirements applicable to interim HLDTs in 2004–2006. Instead, small volume HLDT manufacturers would simply comply with the interim standards, including the corporate average NO_X standard, in 2007 for 100% of their vehicles. During model years 2004–2006, these same small volume manufacturers would comply with any of the interim bins of HLDT standards for 100% of their HLDTs.[84]

Also, we will continue to apply the federal small volume manufacturer provisions, which provide relief from emission data and durability showing and reduce the amount of information required to be submitted to obtain a certificate of conformity. In addition, the CAP2000 program contains reduced in-use testing requirements for small volume manufacturers. Under section V.B.1. below, we describe and request comment on possible additional special provisions for certifiers that qualify as small businesses.

Our proposal to exempt small volume manufacturers from the Tier 2 phase-in requirements eliminates a dilemma that the phase-in percentages might pose to a manufacturer that has a limited product line, i.e., how to address percentage phase-in requirements if the

[82] California Evaporative Emission Standards and Test Procedures for 2001 and Subsequent Model Motor Vehicles; September 18, 1998. Prepared for the November 5, 1998 Hearing of the California Air Resources Board.

[83] We define small volume manufacturers to be those with total U.S. sales of less than 15,000 highway units per year. Independent commercial importers (ICIs) with sales under 15,000 per year would be included under this term.

[84] For a graphical illustration of the phase-ins through time, see Figure IV.B.–1.

manufacturer makes vehicles in only one or two test groups. We have proposed similar provisions for small entities in other rulemakings. Approximately 15–20 manufacturers that currently certify vehicles, many of which are independent commercial importers (ICIs), would qualify. These manufacturers represent just a fraction of one percent of LDVs and LDTs produced. We do not believe that this provision would have any measurable impact on air quality.

9. Compliance Monitoring and Enforcement

a. *Application of EPA's Compliance Assurance Program, CAP2000.* The CAP2000 program (final rule signed March 15, 1998; **Federal Register** cite not yet available) streamlines and simplifies the procedures for certification of new vehicles and would also require manufacturers to test in-use vehicles to monitor compliance with emission standards. The CAP2000 program was developed jointly with the State of California and involved considerable input and support from manufacturers. As the name implies, it can be implemented as early as the 2000 model year.

In today's document, we are proposing that the Tier 2 and the interim requirements would be implemented subject to the requirements of the CAP2000 program. Certain CAP2000 requirements would be slightly modified to reflect changes to useful lives, standard structure and other aspects of the Tier 2 program, but we are proposing no major changes to fundamental principles of the CAP2000 program.

Although we are proposing changes to useful lives in this document, we are not proposing to amend the 50,000 mile minimum mileage used in manufacturer in-use verification testing or in-use confirmatory testing under the CAP2000 program at this time. The CAP2000 in-use program is not yet implemented and we believe it is appropriate to allow manufacturers to gain experience with procuring and testing vehicles at the 50,000 mile level before making significant changes. However, where one vehicle from each in-use test group would have a minimum mileage of 75,000 miles under the CAP2000 program, we are proposing, consistent with California, to change that figure to 90,000 miles for Tier 2 vehicles.

We may, in our own in-use program, procure and test vehicles at mileages higher than 50,000 and pursue remedial actions (e.g. recalls) based on that data. We may also use that data as the basis to initiate a rulemaking to make changes in theCAP2000 in-use requirements, if the data indicate significant non-conformity at higher mileages.

b. *Compliance Monitoring.* We plan no new compliance monitoring activities or programs for Tier 2 vehicles. These vehicles would be subject to the certification and manufacturer in-use testing provisions of the CAP2000 rule. Also, we expect to continue our own in-use testing program for exhaust and evaporative emissions. We will pursue remedial actions when substantial numbers of properly maintained and used vehicles fail any standard in either in-use testing program.

We retain the right to conduct Selective Enforcement Auditing of new vehicles at manufacturer's facilities. In recent years, we have discontinued SEA testing of new light-duty vehicles and trucks, because compliance rates were routinely at 100%. We recognize that the need for SEA testing may be reduced by the low mileage in-use testing requirements of the CAP2000 program. However, we expect to re-examine the need for SEA testing as standards tighten under the NLEV and Tier 2 programs.

We have established a data base to record and track manufacturers' compliance with NLEV requirements including the corporate average NMOG standards. We expect to monitor manufacturers' compliance with the Tier 2 and interim corporate average NO_X standards in a similar fashion and also to monitor manufacturers' phase-in percentages for Tier 2 vehicles.

c. *Relaxed In-Use Standards for Tier 2 Vehicles Produced During the Phase-in Period.* As we have indicated numerous times in this preamble, the Tier 2 standards we are proposing would be challenging for manufacturers to achieve, and some vehicles would pose more of a challenge than others. Not only would manufacturers be responsible for assuring that vehicles can meet the standards at the time of certification, they would also have to ensure that the vehicles could comply when tested in-use by themselves under the provisions of the CAP2000 program, and by EPA under its in-use (''Recall'') test program.

With any new technology, or even with new calibrations of existing technology, there are risks of in-use compliance problems that may not appear in the certification process. In-use compliance concerns may discourage manufacturers from applying new technologies or new calibrations. Thus, it may be appropriate for the first few years, for those bins most likely to require the greatest applications of effort, to provide assurance to the manufacturers that they will not face recall if they exceed standards by a specified amount.

We are proposing, for Tier 2 vehicles only, that for the first two years after a test group meeting a new standard is introduced, that test group be subject to more lenient in-use standards. These ''in-use standards'' would apply only to Tier 2 Bins 5 and below, only for the pollutants indicated, and only for the first two model years that a test group was certified under that bin. The in-use standards would not be applicable to any test group first certified to a new standard after 2007 for LDV/LLDTs or after 2009 for HLDTs.

The in-use standards we are proposing are shown in Table V.A.–5 below.

TABLE V.A.–5.—IN-USE COMPLIANCE STANDARDS FOR TIER 2 VEHICLES (G/MI)

[Certification standards shown for reference purposes]

Bin No.	Durability period (miles)	NO_X In-use	NO_X certification	NMOG in-use	NMOG certification
5, 4	50,000	0.07	0.05	N/a	0.075, 0.04.
5, 4	120,000	0.10	0.07	N/a	0.090, 0.055.
3	120,000	0.06	0.04	N/a	0.070.
2	120,000	0.03	0.02	0.02	0.010.

We believe manufacturers should and will strive to meet the Tier 2 certification standards for the full useful lives of the vehicles, but we recognize that the existence of such in-use standards poses some risk that a manufacturer might aim for the in-use standard in its design efforts rather than the certification standard, and thus market less durable designs. We do not believe that risk to be significant. We believe that such risks are more than balanced by the gains that could result from earlier application of new technology or new calibration techniques that might occur in a scenario where in-use liability is slightly reduced. Further, we believe that the in-use standards will be of short enough duration that any risks are minimal.

We note that the in-use provisions proposed above are similar to those included in California's LEV II program. We request comment on all aspects of the proposed in-use standards including the appropriateness of and need for separate in-use compliance standards for the early years of the Tier 2 program.

d. *Enforcement of the Tier 2 and Interim Corporate Average NO_X Standards.* Under the proposed programs, manufacturers could either report that they met the relevant corporate average NO_X standard in their annual reports to the Agency or they could show via the use of NO_X credits that they have offset any exceedence of the corporate average NO_X standard. Manufacturers would also report their NO_X credit balances or deficits.

The averaging, banking and trading program would be enforced through the certificate of conformity that the manufacturer would need to obtain in order to introduce any regulated vehicles into commerce. The certificate for each test group would require all vehicles to meet the applicable Tier 2 emission standards from the applicable bin of the Tier 2 program, and would be conditioned upon the manufacturer meeting the corporate average NO_X standard within the required time frame. If a manufacturer failed to meet this condition, the vehicles causing the corporate average NO_X exceedence will be considered to be not covered by the certificate of conformity for that engine family. A manufacturer would be subject to penalties on an individual vehicle basis for sale of vehicles not covered by a certificate. These provisions would also apply to the interim corporate average standards.

As outlined in detail in the preamble to the final NLEV rule, EPA would review the manufacturer's sales to designate the vehicles that caused the exceedence of the corporate average NO_X standard. We would designate as nonconforming those vehicles in those test groups with the highest certification emission values first, continuing until a number of vehicles equal to the calculated number of noncomplying vehicles as determined above is reached. In a test group where only a portion of vehicles would be deemed nonconforming, we would determine the actual nonconforming vehicles by counting backwards from the last vehicle produced in that test group. Manufacturers would be liable for penalties for each vehicle sold that is not covered by a certificate.

We are proposing in today's action to condition certificates to enforce the requirements that manufacturers not sell NO_X credits that they have not generated. A manufacturer that transferred NO_X credits it did not have would create an equivalent number of debits that it would be required to offset by the reporting deadline for the same model year. Failure to cover these debits with NO_X credits by the reporting deadline would be a violation of the conditions under which EPA issued the certificate of conformity, and nonconforming vehicles would not be covered by the certificate. EPA would identify the nonconforming vehicles in the same manner described above.

In the case of a trade that resulted in a negative credit balance that a manufacturer could not cover by the reporting deadline for the model year in which the trade occurred, we propose to hold both the buyer and the seller liable. This is consistent with other mobile source rules, except for the NLEV rule as discussed below. We believe that holding both parties liable will induce the buyer to exercise diligence in assuring that the seller has or will be able to generate appropriate credits and will help to ensure that inappropriate trades do not occur.

In the NLEV program we implemented a system in which only the seller of credits would be liable. In the preamble to the final NLEV rule (*See* 62 FR 31216), we explained that a multiple liability approach would be unnecessary in the context of the NLEV program given that the main benefit to a multi-party liability approach would be to ''protect against a situation where one party sells invalid credits and then goes bankrupt, leaving no one liable for either penalties or compensation for the environmental harm.'' Our preamble stated further that EPA would not necessarily take the same approach for ''other differently situated trading programs.''

The NLEV program was implemented to be a relatively short duration program, during which time we could expect relative stability in the industry. Also, given that NLEV is a voluntary program of lower than mandated standards, we did not expect that the smallest manufacturers would opt in. These are the companies whose stability is most in jeopardy in a dynamic and very competitive worldwide business.

We currently believe that the Tier 2 program and its framework will remain for many years. We note that the program is not scheduled for complete phase-in for almost nine years after the publication of this proposal. All manufacturers, large and small, will ultimately have to meet the Tier 2 standards. We cannot predict that in the Tier 2 time frame there will not be companies that leave the market or are divided between other companies in mergers and acquisitions. Thus we believe it is prudent to implement a program to provide inducements to the seller to assure the validity of any credits that it purchases or contracts for. However, we request comment on whether we should implement a program that would only deem the seller to be in violation if it sold credits it could not supply.

10. Miscellaneous Provisions

We are proposing to continue existing emission standards from Tier 1 and NLEV that apply to cold CO, certification short testing, refueling, running loss, idle CO for LDTs, and highway NO_X. We are not proposing to continue the 50 degree (F) standards and testing included in the NLEV program. The 50 degree standards are a part of the NLEV program because that national program adopted California requirements virtually in their entirety. These standards had not previously been part of any federal program. We request comment on the need and the associated burden for any of the standards mentioned in this paragraph.

B. Other Areas on Which We are Seeking Comment

1. LDV/LDT Program Options

The alternatives for which we seek comment would have impacts on the level of emission reductions achieved by the program as well as on the cost and technological impacts of the program. Any decision to adopt an alternative would have to consider those factors. We welcome comments on all of the options described below. Commenters should address cost, technological feasibility and emission impact whenever possible.

a. *Alternatives to Address Stringency of the Standards.*

i. *Alternative Standards and Implementation Schedules.*

We believe that the Tier 2 standards and phase-in schedule contained in this proposal provide appropriate lead time and flexibility for manufacturers to achieve cost-effective emission reductions in a reasonable time period. Further, our standards and phase-in schedules are reasonably harmonized with California's LEV II program to facilitate the sale of 50-state vehicles and to minimize the administrative burdens involved with having to meet the requirements of both California and EPA simultaneously. We believe our proposed fuels provisions will ensure that appropriate fuels are available to enable Tier 2 vehicles to provide substantive in-use emission reductions. Some have suggested delays in the program to 2007 and later. However, many states need reductions as soon as possible for 2007 NAAQS compliance, so there is a need for an aggressive but achievable implementation schedule.

Nevertheless, we are interested in reviewing alternative standards, implementation schedules and averaging schemes. Therefore we request comment on all aspects of the standards and schedules we are proposing today, including the interim standards and schedules, and we request comment on what alternative standards and implementation approaches might provide comparable emission reductions that are cost-effective in the same time frame as our proposal.

We recognize that the Tier 2 program as proposed today does not provide for further reductions in average certification levels after 2008 as California's LEV II program does. We request comment on the technological feasibility, necessity, cost and likely benefits of further reductions in corporate average standards after 2009, including comments on the reduction of the corporate average NO_X standard to a level of approximately 0.05 g/mi in the 2011–2012 time frame. We also request comment on a traditional, non-averaging standard of 0.07 g/mi NO_X with related standards for NMOG, CO, HCHO, and PM in the 2011–2012 time frame, applicable to all LDVs and LDTs.

ii. *Use of Family Emission Limits (FELs) Rather than Bins.*

A bins-based program with an overarching corporate average standard has worked well in California for many years and is being implemented nationwide beginning in 1999 under the NLEV program. We believe that a phased in, bins-based program is the best way to implement the Tier 2 exhaust emission standards and, at the same time, encourage the development of advanced emission control technology. We believe that manufacturers of light duty vehicles and trucks are accustomed to such programs and will appreciate the flexibility and opportunities for 50-state certification that a bins-based program affords.

We are aware, of course, that in other EPA mobile source emission programs, we have implemented averaging standards that were not based upon bins. In these programs, manufacturers declare a family emission limit (FEL) either above or below the averaging standard set by EPA. The FEL becomes the standard for that family. Similar to the bins approach, manufacturers compute a sales weighted average for the subject pollutant at the end of the model year and then determine credits generated or needed based on the distance of that average above or below the standard.

In an FEL based program, every test group can have a different FEL—essentially there is an unlimited continuum of bins to choose from (although there is usually an upper limit or cap on the FELs). The FEL approach adds flexibility and could increase the incentive for cost-effective improvements in vehicle emissions performance. Under a bins approach, a manufacturer is limited to step-wise improvements. An FEL approach could provide incentive for manufacturers to realize smaller, low cost emissions improvements that could be achieved, for example, through engine re-calibration.

However, FEL-based programs create other concerns. One concern with an FEL approach is that it may be viewed as providing too much flexibility since a manufacturer could request a change in an FEL based on a change in desired compliance margin above the certification level or based on concern about its credit balance rather than a change in technology. In EPA's FEL-based programs, it is not uncommon for a manufacturer to declare an FEL that is identical to its certification level. It is also not uncommon for a manufacturer to change its FEL several times during a model year, based, among other reasons, on the availability of or need for credits. In a bins approach, such changes are unlikely, since a change in bins involves more of an increment in emissions and involves compliance with all pollutants in that bin. Consequently, a bins approach eases EPA's compliance monitoring burden. It provides additional assurance that expected emission reductions will occur in use because some vehicles may ''over-qualify'' for their bin resulting in greater than expected reductions than if they exactly met the standard for that bin. Of course, an FEL approach could be modified to restrict or prohibit changes in certification levels during a model year.

Also, in an FEL-based program, it may be necessary to establish corporate average standards for other pollutants besides NO_X. These standards would then require manufacturers to establish FELs for additional pollutants. In a bins-based program, the standards for the other pollutants are simply set by the different bins.

An FEL approach could also lead to additional complexity in manufacturer in-use testing under the CAP2000 program and in EPA in-use testing because if FEL changes are made, the issue of which standard to measure compliance against arises as does the issue of how many vehicles to test for each different FEL. If we were to adopt an FEL approach, we would have to consider significant changes to the in-use provisions of the CAP2000 program to assure that all variations of a test group were adequately covered by manufacturer in-use testing.

We request comment on the appropriateness and need for an FEL-based program for the Tier 2 and/or interim standards. Commenters supporting the use of an FEL-based program should also provide comment as to how EPA can best manage the issues related to in-use testing and how EPA can best assure that FEL changes are closely linked to real changes in vehicle emissions.

iii. *Use of Different Averaging Sets.*

We chose for our proposal the broadest possible—and therefore most flexible—averaging set for the Tier 2 vehicles. We are proposing that, beginning in 2009 when phase-in of all vehicles is complete, all LDVs and LDTs could be averaged together to meet the corporate average NO_X standard. We believe this approach is appropriate because it treats LDTs like LDVs, considering that LDTs are used as passenger cars much of the time. Also, by permitting this broad averaging, a manufacturer of larger LDTs that might have difficulty meeting a 0.07 g/mi NO_X level can certify the LDTs to Bin 6 or 7 and offset the emissions of these trucks with cars or smaller trucks that it certifies to levels below 0.07 g/mi.

While we believe our proposed averaging program is appropriate, we recognize that most manufacturers do not produce larger LDTs and may be able to meet the corporate average NO_X standard of 0.07 g/mi with less overall effort. Therefore, we request comment as to whether another approach to averaging might be more appropriate such as a segregated approach where LDTs are averaged separately from LDVs or where HLDTs (LDT3s and 4s) are averaged separately from LDV/LLDTs.

iv. *Different Standards for Different Categories of Vehicles.*

We have explained several times in this preamble that we believe the same standards should apply to all LDVs and LDTs because LDTs are so often used as passenger vehicles, and because the standards are feasible for all LDVs and LDTs. The technological challenge may be greater for larger trucks, so our proposal provides additional leadtime and a later start date for HLDTs to provide more opportunity to resolve potential problems. However, we recognize that other approaches exist that could yield comparable environmental benefit. Therefore, we request comment on other approaches such as one that would employ a lower corporate average NO_X standard for LDV/LLDTs, with a higher corporate average standard for HLDTs.

v. *Consideration of Special Provisions for the Largest LDTs and Advanced Technology.*

California has adopted a provision in its LEV II program, under which a manufacturer could certify up to 4 percent of its larger LDTs to a higher NO_X standard. These trucks could meet a 0.10 g/mi NO_X standard rather than a 0.07 g/mi NO_X standard, provided they have a payload of at least 2500 pounds. California chose the figure of 4% because it approximates the fraction of such trucks in the largest volume manufacturer's fleet.

We have not proposed such an option in the federal program because we are providing additional lead time and compliance on average for all cars and trucks beginning in 2009. Nevertheless, we do recognize that the largest trucks will likely require the greatest application of emission control technology to comply with Tier 2 standards and we expect that larger trucks will likely be the last, and the most difficult, vehicles to phase into the Tier 2 program.

In the context of the flexibilities already proposed for the federal program, we request comment on the need for and environmental impact of additional program flexibility for the largest trucks. One option we have considered would allow manufacturers to exclude a small fraction (perhaps 4 percent) of their largest Tier 2 trucks (HLDTs) from the corporate average NO_X calculation beginning in 2009 and lasting through approximately model year 2011. These trucks would still be subject to a NO_X standard of 0.20 g/mi and all other standards and provisions of the Tier 2 program, including the requirement to fit within a Tier 2 bin for other emission standards.

This provision would provide a less stringent standard for the heaviest LDTs. We believe these LDTs are the most likely to be used primarily for work and commercial purposes, while at the same time having the most difficulty complying with Tier 2 requirements. We request comment on all aspects of this provision, including whether the allowable sales fraction (4%) and payload minimum (2500 pounds) set by California would be appropriate for the federal provision, and whether such a concept should also be applied to only LDT4s or both LDT3s and 4s. Supporters of such an approach should comment on the appropriate allowable sales fraction for the interim vehicles.

Some have suggested that a potential way of providing flexibility for advanced technology vehicles would be to provide bins with less stringent standards while retaining the stringency of the 0.07 NO_X average. These additional bins would augment the current flexibilities offered to manufacturers. We request comment on this idea, specifically on including additional bins with NO_X standards up to 0.60 g/mi, with any other modifications that are appropriate. We also ask comment on whether such bins should be a temporary part of the Tier 2 program.

vi. *Measures to Prevent LDT Migration to Heavy-Duty Vehicle Category.*

Existing regulations define a light-duty truck to be any motor vehicle rated at 8500 pounds gross vehicle weight rating (GVWR) or less that has a curb weight of 6000 pounds or less and that has a basic frontal area of 45 square feet or less, which is:

- Designed primarily for purposes of transportation of property or is a derivation of such a vehicle, or
- Designed primarily for transportation of persons and has a capacity of more than 12 persons, or
- Available with special features enabling off-street or off-highway operation and use.

For the heaviest LDTs, we are concerned that manufacturers may, in some cases, find it attractive to add GVWR capacity, curb weight or frontal area to their vehicles such that they would no longer meet one or more of the criteria to be considered an LDT. The vehicles would then fall into the heavy-duty category and would be subject to less technologically challenging standards.

We would like to develop reasonable restrictions to prevent this ''gaming'' of the LDT definition. The ideal restrictions would prevent migration of LDTs above the limiting criteria, but would not impact vehicles with legitimate needs to be outside, but close to, the LDT definition. Our objective is complicated by the fact that many LDTs currently have derivatives or corresponding models that are over 8500 pounds GVWR.

We have considered various approaches to restrictions on LDTs. Some of the ideas we have considered are as follows:

- Require all complete trucks in the 8500–10,000 pound GVWR range to meet light-duty standards.
- Raise the GVWR cutoff from 8500 pounds to some other number such as 8750, 9000 or 9500 pounds.
- Require manufacturers of vehicles that are above but close to any of the three size criteria to provide justification that they cannot accomplish their intended function if built to a lower size criterion.
- Require manufacturers to provide supporting data, surveys, etc., that vehicles above, but close to, any of the LDT cutoffs are primarily used for commercial purposes.

We request comment on all aspects of this vehicle migration issue, including specific comment on the ideas presented above and on other approaches that might be appropriate. This discussion serves as notice that we are very likely to finalize a provision to address this vehicle migration issue. You are encouraged to consider the approaches we have outlined above and provide specific suggestions on other approaches as well as comments as to the need for such controls, their feasibility and their cost.

In the longer term, the best way to address the vehicle migration issue is to implement standards for complete heavy-duty vehicles that have a stringency comparable to their HLDT counterparts. In the near future, we expect to publish an NPRM addressing emissions from gasoline-fueled heavy-duty engines and vehicles for 2004 and later model years. As part of that effort we are considering chassis-based standards for gasoline-fueled complete vehicles between 8,500 and 14,000 lbs GVWR. The degree to which such standards discourage migration depends upon the relative stringency of the standards. EPA requests comment on the potential effectiveness of such a strategy in addressing migration concerns and the timing and level of emission standards necessary to do so.

vii. *Use of Non-conformance Penalties (NCPs).*

NCPs are monetary payments that manufacturers can pay to meet an adjusted standard in lieu of complying with a prescribed emission standard or set of emission standards. *See* CAA section 206(g). Current regulations at 40 CFR part 86 Subpart L provide for NCPs for HLDTs, and for heavy-duty engines. However, in order to establish NCPs for a specific standard or set of standards for these vehicles and engines, EPA must first determine that (1) substantial work will be required to meet the standard for which the NCP is offered; and (2) that there will be a manufacturer that is a technological laggard in complying with that standard. EPA must also, through rulemaking, determine compliance costs so that the penalty rates can be established appropriately.

NCPs were used extensively by manufacturers of on-highway heavy-duty engines in the late 1980s, prior to the implementation of our heavy-duty averaging, banking and trading program. Since that time, their use has been rare. We believe manufacturers have used the flexibility of an averaging, banking and trading scheme as a preferred alternative to incurring the monetary losses associated with NCPs.

We are not proposing NCPs for HLDTs in the primary Tier 2 program or in the interim programs. This is because we believe that the NO_X averaging program we are proposing makes it unlikely that the criteria for NCPs mentioned above will be met, as NO_X credits from other vehicles may be used to enable HLDTs to meet the 0.07 g/mi average NO_X standard.

We have considered whether NCPs might be appropriate for the Tier 2 diesel particulate standards, for which our proposal contains no averaging provisions. We are not proposing PM NCPs for those diesel powered trucks, but we request comment on whether such NCPs would be appropriate. We believe that appropriate technologies will be available from component vendors and diesel engine suppliers. We request comment on the need for and appropriateness of NCPs for any Tier 2 standard for HLDTs.

viii. *Additional NO_X Credits for Vehicles Certifying to Low NO_X Levels.*

There is currently substantial work underway to develop vehicles with extremely low emissions. We believe that it is appropriate to encourage such technology by providing incentives for its use. Consequently, we are requesting comment as to whether we should implement a provision by which manufacturers can earn additional NO_X credits for certifying to levels below 0.07 g/mi. As we envision such a provision, manufacturers would be allowed, in the calculation of their year end corporate average NO_X level, to multiply the number of vehicles sold which are certified to bins below 0.07 g/mi NO_X by some preset multiplier, or set of multipliers. For example, the number of vehicles certified to the 0.04 bin might be multiplied by 1.5, those in the 0.02 bin might be multiplied by 2.0 and those in the 0.0 bin (ZEVs) might be multiplied by 3.0.

We recognize that such a program would enable manufacturers to use more credits than actually generated in use, and that the use of these credits would likely result in some additional NO_X emissions. However, we believe that it may be appropriate to provide inducements to manufacturers to strive for ever lower NO_X emissions and that these inducements may help pave the way for greater and/or more cost effective emission reductions from future vehicles. We request comment on all aspects of such incentive credits. Issues related to these credits include the value of a multiplier or multipliers, whether early credits should be subject to the multipliers, and whether there should be a ''sunset'' provision to limit the time period in which manufacturers could obtain and/or use these extra credits. We request comment on a sunset year of 2009, since it is the end of the proposed Tier 2 program phase-in.

ix. *Incentives for Manufacturers to Bank Additional Early NO_X credits.*

We are interested in exploring any reasonable approaches that would provide incentives to manufacturers to produce vehicles meeting the 0.07 g/mi NO_X standard earlier than required. We believe that early certification to this level will help manufacturers gain experience with new or enhanced technologies on a limited scale before they must be applied to the entire fleet, and that such experience would have a positive, although hard to quantify, environmental benefit.

We have proposed an approach elsewhere in this preamble that permits manufacturers to utilize alternative phase-in schedules. Manufacturers that introduce Tier 2 vehicles before the first required year in the primary phase-in schedule could follow a more flexible phase-in path to 100% compliance than required under the primary option. Manufacturers would also be able to generate NO_X credits if these ''early'' vehicles met a corporate average NO_X level of less than 0.07 g/mi.

We have considered whether a mechanism that provided additional NO_X credits could induce manufacturers to introduce more Tier 2 vehicles sooner than required. Such a mechanism might substitute a number higher than the 0.07 g/mi NO_X standard in the credit calculation so that the manufacturer would subtract its corporate average NO_X level from, say, 0.10 and then multiply the difference by the number of Tier 2 vehicles to determine credits earned. While we believe such a scheme might induce manufacturers to accelerate the introduction of Tier 2 vehicles, we have concerns about whether this approach would lead to windfall credits and whether we would need to employ a discount to compensate for them. Should the resulting credits have finite or infinite life? Should we apply such a scheme to LDV/LLDTs only; or should we also apply it to HLDTs; and should we apply such a scheme to the interim standards for HLDTs? We request comment on these and all other aspects of permitting additional NO_X credits for Tier 2 and interim vehicles.

x. *Flexibilities for Small Volume Manufacturers and Small Businesses.*

In section V.A.8. above, we propose to waive the Tier 2 phase-in requirements for small volume manufacturers.[85] These manufacturers, which each produce 15,000 or fewer vehicles per year, would simply comply with the 100 % requirement in 2007 (2009 for HLDTs).

Some very small volume manufacturers of LDVs and LDT1s and LDT2s elected not to opt into NLEV and thus will produce Tier 1 vehicles during the NLEV program. We are seeking comment about the burden that our interim standards might impose on very small manufacturers in 2004 given that they will have to meet the Tier 2 standards no later than 2007 under today's proposal. Similarly we are concerned about the burden that the interim standards might impose on any small volume HLDT manufacturers. We request comment on the need for and appropriateness of a provision that would waive the interim standards for very small volume manufacturers who produce, say, less than 1,000 vehicles per year, or who qualify as small businesses (see below).

The panel convened under the Small Business Regulatory Enforcement Fairness Act (SBREFA),[86] recommended that we seek comment on five provisions outlined below to ease our

[85] A ''small volume manufacturer'' is not necessarily a ''small business''. Rather, ''small volume manufacturer'' is an EPA term that refers to entities whose annual on-highway sales are 15,000 or fewer vehicles per year. However, most if not all small businesses covered under this discussion are also ''small volume manufacturers,'' though most small volume manufacturers are not small businesses.

[86] This panel was convened, consistent with SBREFA, by EPA, the Small Business Administration, and the Office of Management and Budget to review of the likely impact of Tier 2 requirements on small businesses.

proposal's impact on small businesses. These provisions, if adopted, would apply to ''small businesses'' as defined by Small Business Administration. The size of a ''small business'' varies by industry type as represented by SIC codes. Tables V.B.–2 and V.B.–3 contain the SIC codes that could potentially be impacted by the Tier 2 rule and the maximum number of employees or maximum revenue a business can have to be considered a small business.

TABLE V.B.–2.—SBA SMALL BUSINESS CATEGORIES FOR SMALL INDEPENDENT COMMERCIAL IMPORTERS

SIC code	Description	Size standard (annual revenues in millions)
7533	Auto Exhaust System Repair Shops	$5
7549	Automotive Services	5
8742	Management Consulting Services	5

TABLE V.B.–3.—SBA SMALL BUSINESS CATEGORIES FOR ALTERNATIVE FUEL VEHICLE CONVERTERS

SIC code	Description	Size standard ($ =annual revenues)
3592	Carburetors, Pistons, Rings and Valves	500 employees.
3714	Motor Vehicle Parts and Accessories	750 employees.
5172	Petroleum Products	100 employees.
5984	Liquefied Petroleum Gas Dealers	$5 million.
7549	Automotive Services	$5 million.
8742	Management Consulting Services	$5 million.
8931	Commercial Physical Research	500 employees.

The vast majority of businesses in these categories are not subject to these EPA requirements. However, some businesses in these categories may in fact manufacture LDVs and LDTs or may modify vehicles produced by others in a manner that will subject them to the requirements applicable to manufacturers under EPA regulations. For example, Independent Commercial Importers (ICIs) modify imported motor vehicles into configurations that they certify to meet federal emission requirements. Approximately 15–20 small businesses qualified as manufacturers and received certificates of conformity each year over the last five years.

For simplicity, and consistency with the report of the SBREFA panel, we refer to these small businesses as small certifiers in the following discussion. The requirements to certify continue to apply only to parties that meet the definition of ''manufacturer.''

Consistent with the recommendations of the SBREFA panel, we request comment on the following ideas:

For small certifiers that convert imported vehicles to U.S. standards (independent commercial importers or ICIs) and for small certifiers that convert vehicles to operate on alternative fuels, provide a delay in required compliance of two years after the particular model vehicle is certified to Tier 2 standards by the original equipment manufacturer.

This provision would provide time for development of appropriate emission control systems and test data for small businesses who may need to first obtain a regular production vehicle certified by the OEM before they can begin work.

Although it was not a specific recommendation of the SBREFA panel, we are also requesting comment on whether ICIs should be exempted from the Tier 2 and interim fleet average NO_X standards. ICIs may not be able to predict their sales of vehicles and control their fleet average emissions because they may be dependant upon vehicles brought to them by individuals attempting to import uncertified vehicles. Presently, the NLEV requirements are optional for ICIs and ICIs are specifically exempted from complying with the fleet average NMOG standard under the NLEV program. (*See* 40 CFR 85.1515(c)). Further, a prohibition in the current ICI regulations specifically bars ICIs from participating in any emission related averaging, banking or trading program. (*See* 40 CFR 85.1515(d)). If we do not amend this prohibition, the likely outcome would be that ICIs could choose any bin to certify their vehicles and would pick the least stringent standards.

Given the historically very low sales of ICIs and the probable challenges that even the least stringent Tier 2 and interim non-Tier 2 bins will impose upon ICIs, we do not expect ICIs to grow significantly in number or size. Therefore, we do not expect that provisions exempting or prohibiting ICIs from the fleet average NO_X standard would have any air quality impact. However, we request comment on all aspects of the applicability of the fleet average NO_X standards to ICIs.

Establish a credit program and provide incentives for large manufacturers so that they would make credits available to small certifiers.

This provision would address the problem inherent with any emission credit trading program that manufacturers holding credits don't have to trade them. While the panel proposed this option, it did not provide any thoughts on what type of incentives might be appropriate and necessary to induce larger manufacturers to supply credits at reasonable prices to small businesses.

Develop a program to provide credits to small certifiers for taking older vehicles off of the road (i.e., a scrappage program).

Because older vehicles often have very high emissions, removing one from use could more than offset the emissions of a new vehicle produced by a small certifier that was unable to fully comply with the Tier 2 standards. Scrappage programs must be designed so that they remove vehicles from the fleet that see significant annual mileage. They must be adequately funded and managed. They must have controls and oversight to ensure that they don't remove vehicles that would have been scrapped anyway.

Design a case-by-case hardship relief provision that would delay required *compliance for small certifiers that demonstrate that they would face a severe economic impact from meeting the Tier 2 standards.*

We have implemented case-by-case hardship provisions in some rules subject to specific limiting constraints. Typically, these would provide that small businesses that have tried all other regulatory options and apply in writing before they experience nonconformity, could obtain a 1 year delay in the implementation of the standards. The small business would have to show that failure to comply was the fault of external and extenuating circumstances and that inability to sell the subject vehicles would have a major impact on the company's solvency.

If the Tier 2 program involves a phase-in of standards, allow small certifiers to comply at the end of such a phase-in.

As indicated at the beginning of this section, we are proposing this option for all phase-ins associated with the Tier 2 program including the phase-in of the Interim standards for HLDTs (see Section V.A.8. above).

We request comment on the need for, appropriateness and environmental impact of all of the items proposed by the SBREFA panel. Also, we request comment on whether any such provisions would be necessary and appropriate for the interim standards for non-Tier 2 vehicles.

xi. *Adverse Effects of System Leaks.* For the emission control system to operate as designed, the air-fuel (A/F) ratio must stay within strictly prescribed limits that vary with vehicle/engine operating conditions and engine controls must respond quickly to the slightest changes in this ratio. Even the smallest air leak in either the exhaust manifold or exhaust pipe or any related connection can provide the oxygen sensor incorrect information on the oxygen content of the exhaust gas it uses to calibrate the engine A/F ratio.

Some manufacturers have taken steps to address this concern as part of their overall design process by incorporating features such as corrosion-free flexible couplings, corrosion-free steel, and improved welding of catalyst assemblies. EPA is concerned that either as a result of manufacturing or installation errors or errors in a repair action, there will be an unintentional and unobserved increase in emissions and perhaps a failure to meet FTP and a SFTP emission standards in-use.

EPA seeks comment on design or onboard monitoring requirements that might be useful to address this concern. EPA would also seek comment on a provision that would require a manufacturer to demonstrate through engineering analysis or design that such possibilities have been taken into account.

xii. *Consideration of Other Corporate Averaging Approaches.*

We welcome comments on the pros and cons, including regulatory burden, of establishing a combined NMOG plus NO_X corporate average standard in lieu of either the proposed NO_X average or a California-like NMOG average. We also request comments, if not provided in response to Section IV.B. above, on the concept of requiring a declining corporate average NO_X standard or a declining corporate average NMOG standard at the federal level. For example, we would consider a declining average approach that reduces NMOG/NO_X corporate average emissions by 20–25% over the period 2008–2012, or nominally to 0.07 NMOG/0.05 NO_X. Such a reduction might involve a reduction in gasoline sulfur levels as discussed in Section IV.E.2. above. We also seek comment on the idea of eliminating the averaging concept in 2011 or 2012 and setting the LDV/LDT standards at the levels of Bin No. 5 in Table IV.B.-2 (0.07 g/mi NO_X plus the other standards). Commenters should address the cost and feasibility of these approaches.

2. Tighter Evaporative Emission Standards

We considered proposing tighter evaporative emission standards, including California's LEV II standards for evaporative emissions, shown in Table V.B.-4 below.

TABLE V.B.–4.—CALIFORNIA'S LEV II EVAPORATIVE HYDROCARBON STANDARDS

[Grams per test]

Vehicle class	Three day diurnal + hot soak standard	Supplemental two day diurnal + hot soak standard
LDV	0.50	0.65
LDT1 AND LDT2	0.65	0.85
LDT3 AND LDT4	0.90	1.15

These standards are based on an evaporative emission test procedure that is conducted at different temperatures using fuel with lower vapor pressure than the corresponding federal evaporative test procedure. Under current evaporative standards, California accepts the results of federal evaporative testing, because it represents a worst case test. We do not know whether California's standards are feasible under the federal test conditions.

We are concerned about evaporative hydrocarbons and we recognize that they constitute a portion of the mobile source VOC inventory that will be similar in size to the light duty exhaust contribution when NLEV exhaust standards are in place. Our proposed standards, which are found in section IV.B.4.a. above, are roughly in line with current average certification levels but will nonetheless yield real in-use evaporative reductions as manufacturers reduce certification levels to gain safety margins under the new standards. These standards will also prevent manufacturers from ''backsliding'' from their current low certification levels upward toward the existing standards as they seek cost reductions. Our proposed standards will require manufacturers to capture the abilities of available fuel system materials to minimize evaporative emissions. Further, we are proposing certification enhancements to address the impact of alcohol fuels on evaporative emissions, and we expect that these measures will lead to more uniform use of lower permeability materials that will result in in-use reductions in non-attainment areas where alcohol fuels are the most prevalent.

We request comment on the appropriateness and cost effectiveness of applying tighter evaporative standards in the federal program.

3. Credits for Innovative VOC, NO_X and Ozone Reduction Technologies Not Appropriately Credited by EPA's Emission Test Procedures

Compliance with the current and proposed EPA motor vehicle emission standards is based on the emission performance of a vehicle over EPA's prescribed test procedure. While this test procedure addresses many of the aspects of a vehicle's impact on air quality, it does not address all such impacts. Two developing technologies have been brought to EPA's attention that have shown significant potential to improve ozone-related air quality, but that would not do so over the current EPA test procedure.

The first example is a device that removes ozone from the air as the vehicle is driven. A major producer of automotive catalysts, Englehard, has approached both California and EPA with a proposal for a technology (called Premair) in which vehicle radiators would be coated with a catalyst that converts ambient ozone to oxygen. In its CalLEVII program, California has adopted some basic ground rules concerning the types of information that would have to be submitted in order to certify such ozone reduction technologies and determine the amount of allowable NMOG credits.[87] This determination would be made on a case-by-case basis. The manufacturer would have to provide an evaluation of the system's performance and durability, as well as a description of the on-board diagnostic strategy to monitor the performance of the device in use. The NMOG credit would be based upon the running of an approved airshed model, which would determine the amount of NMOG emission reductions that would produce the same change in one-hour peak ozone as the use of the ozone reduction device being evaluated.

Englehard has asked EPA to develop a similar procedure to that adopted by ARB and to consider granting their technology a NO_X credit, as well as an NMOG credit. The manufacturer of the vehicle employing Premair would then have the option of which credit to use.

There are a number of issues that would have to be resolved before such credits could be granted, including:

- The methods to be used to certify in-use performance over the useful life of the vehicle,
- The requirement for, and the design and certification of, an onboard diagnostic system to monitor in-use performance, and
- Which airshed model to use, including what cities and episodes to use in modeling the 8-hour peak ozone reduction, and
- The methods for determining either the NMOG or NO_X credit, or both.

EPA has placed information provided to date by Englehard in the docket to this rule, and requests comments on the appropriateness of such credits, and on the procedures that should be used to determine those credits, should we proceed.

The second example is an insulated catalyst. The insulation retains heat for extended periods of time, increasing the catalyst temperature when the engine is started and reducing the time required for the catalyst to reach an operational temperature. This technology can reduce cold start emissions for engine off times (called soaks) of 24 hours or less. The vast majority of engine soaks in-use are less than 24 hours. However, EPA's test procedure only tests emissions at two fairly extreme soak times: 10 minutes and 12–36 hours. The 10 minute soak is so short that even an uninsulated catalyst is warm enough to quickly begin working upon restart. The 36 hour soak is beyond the practical limit of cost-effective insulating techniques.

In 1994, as part of its proposed SFTP standards, EPA proposed adding an intermediate soak of 1 hour to the test procedure, due both to the large number of in-use soaks falling between the current 10 minute and 12–36 hour soaks and to the desire to encourage catalyst technology that reduced cold start emissions for such intermediate soaks. EPA did not promulgate this aspect of its SFTP standards, due in part to concerns about the cost effectiveness of mandating such controls. However, the efficacy of such technology was not questioned. Thus, there appears to be little reason to prohibit a manufacturer from using such technology to reduce in-use emissions in lieu of other technology needed to meet the proposed Tier 2 standards.

As mentioned above concerning Premair, a methodology would need to be developed to estimate the impact of an insulated catalyst, or other any other similar technology, on in-use emissions so that equivalent NMOG and NO_X emission credits could be determined. Also, procedures for certifying in-use performance and durability and onboard diagnostics would also have to be addressed. EPA requests comments on the appropriateness of allowing emission credits for insulated catalysts and other technologies not appropriately assessed under current test procedures. EPA also requests comments on the procedures to be used to develop such credits.

EPA also requests comments on whether the credits granted for either ozone or emission reduction technologies should be restricted to the proposed Tier 2 standards, or whether they should also be granted under the current NLEV standards and the proposed interim standards for non-Tier 2 vehicles, as well.

4. Need for Intermediate Useful Life Tier 2 Standards

For our Tier 2 and interim standards we have generally proposed both full useful life and intermediate useful life FTP exhaust emission standards. (See Tables IV.B.–2, –3, –6,–7,–10 and –11.) We have also proposed full and intermediate life SFTP standards. (See Tables V.A.–3 and –4.) Intermediate useful life standards are more stringent than full useful life standards and reflect our experience that better emission performance can be expected at lower mileages.

We are not proposing intermediate useful life standards for the three lowest Tier 2 FTP bins, and we are not proposing intermediate standards for the lowest FTP bin (the Zero Emission Vehicle or ZEV bin) in any case. This is because the full life standards in those bins are already so low as to allow little deterioration between a new vehicle and a vehicle at full useful life.

We request comment on the appropriateness of and need for intermediate useful life and what the environmental consequences might be from deleting intermediate useful life standards for all Tier 2 vehicles and from the interim standards bins that match those of the Tier 2 program.

VI. Additional Proposed Elements and Areas for Comment: Gasoline Program

Section VI.A. presents two additional issues that have some impact on our proposed program: whetherstates are preempted from requiring gasoline sulfur reductions as a result of today's action, and whether other gasoline properties may also need to be controlled in the future. We encourage your comment on all of these issues. Section VI.B. provides additional detailed information about our proposed requirements for establishing compliance with the gasoline sulfur standards, as well as how we will enforce these standards. The major details of our proposed gasoline sulfur control program were explained in Section IV.C.; the information presented here is supplementary.

A. Other Areas for Comment

The following sections raise additional issues that are relevant to our decisions regarding gasoline sulfur control and the design of our gasoline sulfur program. We encourage you to comment on these issues if they are of interest to you.

1. Would States Be Preempted From Adopting Their Own Sulfur Control Programs?

When we adopt federal fuel standards, states are preempted from adopting similar state-level controls. Section 211(c)(4)(A) of the CAAA prohibits states from prescribing or attempting to enforce controls or prohibitions respecting any fuel characteristic or component if EPA has prescribed a control or prohibition applicable to such fuel characteristic or component under section 211(c)(1). This preemption applies to all states except California, as explained in section

[87] See page II–28 of the following California document for a full discussion: Proposed Amendments to California Exhaust and Evaporative Emission Standards and Test Procedures for passenger Cars, Light-Duty Trucks and Medium Duty Vehicles (''LEV II'') and Proposed Amendments to California Motor Vehicle Certification, Assembly-Line and In-Use Test Requirements (''CAP2000''). Released September 18, 1998 for the Air Resources Board Hearing of November 5, 1998.

211(c)(4)(B). For these states other than California, the Act provides two mechanisms for avoiding preemption. First, section 211(c)(4)(A)(ii) creates an exception to preemption for state prohibitions or controls that are identical to the prohibition or control adopted by EPA. Second, states may seek EPA approval of SIP revisions containing fuel control measures, as described in section 211(c)(4)(C). EPA may approve such SIP revisions, and thereby ''waive'' preemption, only if it finds the state control or prohibition ''is necessary to achieve the national primary or secondary ambient air quality standard which the plan implements.''

We are proposing to adopt the sulfur standards pursuant to our authority under section 211(c)(1). Thus, we believe final promulgation of the sulfur standards would result in the clear preemption of future state actions to adopt fuel sulfur controls.[88] States would therefore need to obtain a waiver from us under the provisions described in section 211(c)(4)(C) for all state fuel sulfur control measures adopted following promulgation, unless the state standard were identical to our final sulfur standard. We welcome your comments on our interpretation of the source and effect of federal preemption.

Section 211(c)(4)(A) preempts state fuel controls if EPA has ''prescribed'' federal controls. We read this language to preempt non-identical state standards on the effective date of the standards, as opposed to the date the standards become enforceable. Thus, if the proposed standards are finalized according to our expected schedule, this rulemaking would preempt state actions upon promulgation at the end of 1999, even though the standards would not require sulfur reductions until 2004. This interpretation is consistent with EPA actions applying other federal fuel measures. *See* 54 FR 19173 (May 4, 1989) (noting preemption of Massachusetts state RVP measure before start of first control period for federal RVP). We also believe this interpretation is consistent with the intent behind section 211(c)(4)(A). Though the standards are not immediately enforceable, they will have an immediate impact on refiners' investment decisions. We believe, by adopting 211(c)(4)(A), Congress intended to provide security for these investment decisions by preventing unnecessary conflict between state and federal fuel controls.

[88] Even in the absence of final promulgation of federal sulfur standards, existing federal fuel controls for RFG and conventional gasoline have raised issues of preemption of state fuel sulfur measures. In any case, it is clear that state sulfur standards would be preempted as of the date of promulgation of the proposed federal sulfur standard.

2. Potential Changes in Gasoline Distillation Properties

During the last several years, representatives of the automotive industry have presented information to us suggesting that control of certain gasoline distillation properties can provide reductions in both exhaust hydrocarbon emissions as well as the frequency of performance problems such as hesitation, cold startability, and impeded acceleration. Automotive industry representatives contend that the source of most performance problems—slower atomization and vaporization due to fuels with higher boiling points—also leads to less efficient combustion, and thus higher levels of hydrocarbons in the exhaust.

With regard to Tier 2 vehicles, some automakers have claimed that in-use fuels with high boiling points would impact their ability to control the mixture of air and fuel entering the engine, and thus could result in in-use emissions that are higher than expected based on certification levels. Thus, automakers argue, controls on the distillation properties of gasoline would not only produce emission benefits for the in-use fleet, but would also ensure the viability and benefits of Tier 2 vehicles.

On January 27, 1999, we received a petition[89] from a group of automakers in which they provided a more detailed analysis of the costs and benefits of controlling gasoline distillation properties. In this petition, they specifically requested that the Distillation Index (DI) be capped at 1200 for all summer-grade gasolines nationwide. They have defined the distillation index by the equation 1.5xT10 + 3xT50 + T90 +20xOxy, where T10 represents the temperature at which 10% of the fuel has evaporated in a standard distillation test, and likewise for T50 and T90, and Oxy is the oxygen content contributed by ethanol. This petition includes a study conducted by MathPro Inc.[90] to estimate the feasibility and cost to the refining industry of capping all summer grade gasoline at a DI level of 1200. MathPro concluded that the cost of such control would be approximately 0.4 ¢/gal on average for all summer grade gasoline.

[89] ''Petition to regulate gasoline distillation properties''. Submitted by DaimlerChrysler Corporation, Ford Motor Company, General Motors Corporation, and the Association of International Automobile Manufacturers. Submitted to EPA Administrator Carol Browner on January 27, 1999. EPA Air Docket A–97–10, Document No. II–G–286.

[90] ''Technical and economic implications of controlling the distillation index of gasoline.'' MathPro Inc., October 21, 1998. EPA docket A–97–10, document II–G–268.

We believe that the analyses presented by this petition have merit. However, we do not believe that they are sufficient to justify capping DI at 1200 at this time, since there are a number of issues that it does not address. Before we could formally propose a DI cap, we would need to have a justification for the cap based on air quality need, peer-reviewed estimates of the cost to the refining industry and to consumers, and comparisons of the cost effectiveness of this strategy to that for other potential hydrocarbon control strategies. Therefore, we are not today proposing controls on gasoline distillation properties. However, we request comment on the automakers' DI petition and the included MathPro report in terms of their sufficiency in demonstrating that a DI cap of 1200 is appropriate.

B. Gasoline Sulfur Program Compliance and Enforcement Provisions

1. Overview

We are proposing enforcement mechanisms that track those of the reformulated gasoline/conventional gasoline (RFG/CG) rule, because of significant similarities between the two programs, including refinery average standards, refinery level and downstream level caps, and the generation and use of credits. These features raise similar compliance issues for both programs. Because of the importance of assuring that all gasoline meets the sulfur standards, measures are needed to assure the accuracy of refiner and importer testing, and to assure that the quality of gasoline is not adversely affected downstream of the refinery. Downstream enforcement would be based primarily on EPA sampling and testing, and examination of product transfer documents (PTDs) and other evidence.

More specifically, we are proposing:

- That refiners and importers test each batch of RFG and CG produced or imported for sulfur content and maintain testing records and retain test samples.
- That refiners and importers of gasoline submit reports regarding compliance with averaging and credits provisions.
- That the current attest procedures of the RFG/CG rule[91] be applied to sulfur rule compliance.

[91] 40 CFR part 80 subpart F.

• Enforcement provisions regarding the credit program, to prevent the use, sale or purchase of invalid credits, and to require adjustments to compliance calculations based on use of invalid credits.

• Requirements to ensure compliance by small foreign refiners subject to individual refinery sulfur standards and to ensure the separation of such foreign gasoline from all other gasoline to the U.S. port of entry.

• Downstream maximum sulfur caps, which would apply to all persons in the chain of distribution of gasoline, including distributors, resellers, carriers, retailers and wholesale purchaser-consumers of gasoline.

• Voluntary downstream quality assurance testing by distributors and refiners to help assure compliance.

The sulfur standards proposed today would apply, as in other fuels programs, to all motor vehicle fuel that meets the definition of gasoline. See 40 CFR 80.2. This definition typically includes all the gasoline that is produced and distributed through the gasoline distribution system, including gasoline, such as marina gas, that is ultimately used in nonroad equipment. Such fuel meets the definition of gasoline and is subject to the standards proposed today. For example, where gasoline makes up only a small portion of what a refinery produces, and is perhaps a byproduct of other processing, the refiner could not avoid the sulfur standard by designating the product as marina gasoline or nonroad gasoline. EPA would apply the sulfur standard to the same broad group of products that meets the definition of gasoline for its other gasoline fuel programs.

We are aware that there are certain fuels, such as aviation fuel and racing fuel, that are generally segregated from gasoline throughout the distribution system. Where such fuels are segregated from motor vehicle gasoline and not made available for use in motor vehicles, the fuel would not be subject to sulfur rule standards.[92] We propose that such fuel become subject to the sulfur standards and other regulatory requirements and prohibitions if its segregation from gasoline at any point in the distribution system is compromised. Offering such fuel for motor vehicle use or dispensing such fuel for motor vehicle use would be prohibited. We are also proposing specific PTD requirements and labeling requirements to prevent introduction of high sulfur fuels into motor vehicles. EPA invites comment on whether such fuel should also be subject to refinery level sulfur standards, or whether it should be subject to the standards from the point at which it is made available for use in motor vehicles.

The proposal would clarify the definition of refinery at 40 CFR 80.2(h). Specifically, we are proposing to clarify that ''refinery'' means any facility, including a plant, tanker truck or vessel where gasoline or diesel fuel is produced, including any facility at which blendstocks are combined to produce gasoline or diesel fuel, or at which blendstock is added to gasoline or diesel fuel.[93]

We propose that any oxygenate blender that only adds oxygenate to gasoline or to ''reformulated blendstocks for oxygenate blending'' (RBOB), be exempt from sulfur standards and would not be required to conduct any new testing, or perform any new recordkeeping or reporting, because we believe the sulfur level of EPA-allowed oxygenates added downstream from the refinery is very low. We believe it is an appropriate assumption, barring special circumstances, that the sulfur content of the gasoline will be diluted in proportion to the addition of the oxygenate.

In the remainder of this section we address enforcement issues regarding today's proposed rule that are not discussed in section IV.C.3., above.

2. What Requirements is EPA Proposing for Foreign Refiners and Importers?

As discussed in section IV.C, under today's proposal, standards for gasoline produced by foreign refineries that are not subject to small refiner individual refinery standards would be met by the importer. Standards for gasoline produced by a foreign refinery subject to an individual sulfur rule standard would be met by the foreign refinery, with certain limited exceptions. The provisions would be very similar to the foreign refinery provisions of the RFG/CG rule, under 40 CFR 80.94.

a. What Are the Proposed Requirements for Small Foreign Refiners with Individual Refinery Sulfur Standards?

Under the RFG/CG rule, EPA has promulgated regulations[94] addressing establishment and implementation of individual baselines for CG produced by certain foreign refiners. The purpose of these regulations is to assure the compliance of gasoline supplied from foreign refineries with individual compliance baselines. It includes comprehensive controls, requirements and enforcement mechanisms to monitor the movement of gasoline from the foreign refinery to the U.S., to monitor gasoline quality and to provide for compliance and enforcement as necessary.

Today we are proposing similar requirements that would apply to any foreign refiner that can demonstrate that it meets the small refiner criteria. Foreign refinery baselines would be based on average sulfur levels and the volume of gasoline imported to the U.S. in 1997–98. Any foreign refiners that obtain a foreign refinery sulfur rule baseline would be subject to the same requirements as domestic small refiners with individual refinery sulfur rule standards. Additionally, provisions similar to the provisions at 40 CFR 89.94 would apply, that include:

1. Segregating gasoline produced at the small refinery until it reaches the U.S.;
2. Refinery registration;
3. Controls on product designation;
4. Load port and port of entry testing;
5. Attest requirements; and
6. Requirements regarding bonds and sovereign immunity.

The rationale for these enforcement provisions is discussed more fully in the Agency's August 28, 1997 preamble to the final RFG/CG foreign refineries rule. (See 62 FR 45533 (Aug. 28, 1997)).

By no later than January 1, 2010,[95] all gasoline would be subject to a single national averaged standard and one national refinery level cap. Thus, EPA is proposing that, beginning on that date, the use of foreign small refinery baselines would sunset and standards for all imported gasoline would be met by U.S. importers. With a single national standard and cap, gasoline sulfur content could most readily be monitored at the U.S. importer level, since there would no longer be a special class of gasoline with different standards that would need to be monitored.

b. *What Are the Proposed Requirements for Truck Importers?* The proposed sampling and testing requirements for importers require sampling and testing of each batch of gasoline. For parties that import gasoline into the U.S. by truck, the every-batch testing requirement would include testing the gasoline in each

[92] If a fuel is not segregated throughout the gasoline distribution system, but is fungibly mixed with gasoline, then it becomes a gasoline that is subject to the standard.

[93] This is consistent with all current EPA fuels rules, interpretations, policies and question and answer documents, and is only a clarification.

[94] 40 CFR 80.94.

[95] As stated in section IV.C. of the preamble, small refiner individual refinery standards would sunset January 1, 2008, except for any small refineries that receive a hardship extension not to exceed two years.

truck compartment, or if the gasoline is homogeneous, testing the gasoline in the truck. However, EPA is concerned that this testing requirement may not be feasible for truckers hauling many small loads of gasoline. Since some northern U.S. communities rely, in large part, on gasoline transported into the U.S. by truck from Canadian terminals, these communities could suffer gasoline shortages if this requirement proves too burdensome for truck importers. We therefore propose to allow alternative requirements for truck-imported gasoline only.

i. *Truck Transports of Gasoline (Excluding Gasoline Subject to Small Foreign Refiner Individual Refinery Standards).*

EPA is proposing a limited alternative approach for truck importers in lieu of every-batch testing. This proposal would be based on the importer meeting the 30 ppm sulfur average standard on a per-gallon basis. Under this proposal, the importer would be allowed to rely on the sulfur results of sampling and testing conducted by the operator of the truck loading terminal in Canada. The environmental consequences of this proposal would be neutral, because by meeting the 30 ppm sulfur standard on an every-gallon basis the standard also is being met on average.

The importer would be required to demonstrate the gasoline meets the 30 ppm sulfur standards on an every-gallon basis. The gasoline in the storage tank from which the importer's trucks are loaded would have to be sampled and tested subsequent to each receipt of gasoline into the terminal tank, and these tests would have to show the gasoline meets the 30 ppm sulfur standard. For each truck load of gasoline, the importer would have to obtain documents that accurately state the sulfur content of the gasoline. The importer then would treat each truck load of imported gasoline as a separate batch for purposes of the recordkeeping and reporting requirements.

The terminal operator in most cases would not be subject to United States laws, so the proposal contains safeguards that are intended to ensure the gasoline in fact meets the applicable standard. First, the importer would be required to conduct an independent program of quality assurance sampling and testing of the gasoline dispensed to the importer. This sampling and testing would have to be at a rate specified in the proposed regulations, and the sampling would have to be unannounced to the terminal operator. In addition, EPA inspectors would have to be given access to conduct inspections at the truck loading terminal and at any laboratory where samples collected pursuant to this proposed approach are analyzed. These inspections could be unannounced, and would include gasoline sampling and testing, and record reviews.

EPA requests comment on this proposal for parties that import gasoline by truck. Specifically, EPA requests comment on the provisions that apply to persons located outside the United States, and the need for EPA inspectors to conduct inspections at terminals located outside the United States. In addition, EPA recognizes that the proposed per-gallon standard of 30 ppm is more restrictive than an annual average standard with per-gallon caps, although it provides assurance that gasoline imported by truck will meet the requirements of the sulfur control program. However, establishing an averaged standard with per-gallon caps for truck-imported gasoline would require more substantial recordkeeping, reporting and auditing by the importers and more compliance monitoring by the EPA. EPA requests comments on the alternative of allowing an annual average standard with per-gallon caps for truck importers and the appropriate sulfur standards that should apply under such an approach.

ii. Truck-Imported Gasoline Subject to Small Foreign Refiner Individual Refinery Standards

There are additional compliance concerns related to the gasoline produced by small foreign refiners whose gasoline is imported into the U.S. by truck. The proposed requirements for gasoline produced at a small foreign refinery with an individual baseline, and certified as subject to the individual standard (S–FRGAS), include the necessity of segregating the gasoline from all other gasoline, from the refinery gate to the U.S., so that compliance with standards can be tracked. Under our proposed certified S–FRGAS provisions applicable to other importers, each batch of gasoline must be tested at the load port and port of entry. However, in the case of gasoline imported by truck, each truckload of such gasoline would constitute a batch. Given the small batch volumes for truck imports, the testing and other procedures proposed for certified S–FRGAS may not be feasible. The issue is further complicated because the load port, in effect, stretches from the refinery, through a pipeline and to a terminal in Canada. Therefore, EPA is proposing an alternative to the requirement for testing every truckload of imported certified S–FRGAS.

EPA is proposing that small foreign refiners whose gasoline is exported to the U.S. by truck would, as part of their petition for an individual baseline, submit a plan designed to ensure that certified S–FRGAS remains segregated from all other gasoline from the refinery to the U.S. The proposed plan would be reviewed for approval in conjunction with the baseline petition.

Rather than specifying the precise requirements of such a plan in the regulations, EPA would allow the refiner to develop its own procedures for ensuring that S–FRGAS remains segregated until it reaches the U.S. However, EPA believes that any plan would have to include certain elements. For example, PTDs would have to accompany each transfer of certified S–FRGAS through the distribution system, clearly identifying the origin of the gasoline and prohibiting its commingling with any product other than certified S–FRGAS from that refinery. The refiner may need to enter into contracts with pipelines and terminals, if the gasoline is shipped in this manner, that ensure segregation and prohibit commingling. This certified product could then only be loaded into trucks if they were importing the gasoline into the U.S.

The refiner of such gasoline would have to receive and maintain all such product shipment documents, including U.S. import documents, for five years and review these on an ongoing basis to ensure segregation is maintained until reaching the U.S. To further ensure that this review occurs, EPA is proposing that the refiner's plan would include attest audit procedures to be conducted annually by an independent third party that would review the refiner's procedures and records to ensure that the certified S–FRGAS is segregated at all times. For example, these procedures would likely include volume reconciliation to confirm that product is transferred without commingling. However, additional procedures may be needed to accomplish the goal of ensuring that certified-S–FRGAS remains segregated from all other gasoline.

3. What Standards Would Apply Downstream?

EPA is proposing downstream per-gallon cap standards that would apply to all parties in the distribution system downstream of the refinery-level, including pipelines, terminals, distributors, carriers, retailers and wholesale purchaser-consumers. Downstream standards would help ensure the sulfur level of gasoline remains below the cap level when dispensed for use in motor vehicles, thereby avoiding the adverse emissions consequences of using gasoline with a sulfur content above the cap level.

EPA is proposing that downstream standards would be more lenient than the refinery-level cap standards so that refiners and importers can produce gasoline that equals the refinery-level cap standard. It has been EPA's experience that if a refiner produces gasoline that equals, or almost equals a standard, that gasoline may be shown to violate the standard when subsequently tested at a location downstream of the refinery due to testing variability. As a result, parties downstream of the refinery (primarily pipelines) set commercial specifications for the quality of the gasoline they will accept that are more stringent than the standard that applies to the downstream party. This, in effect, forces refiners to produce gasoline that is ''cleaner'' than the refinery-level standard.

In other fuels programs (for example, the benzene per-gallon standard for RFG) EPA has resolved this concern by announcing enforcement tolerances for fuels standards that apply downstream of the refinery-level, thereby reducing the need for pipelines to set specifications more stringent than the refinery level standards. EPA believes the approach proposed for the gasoline sulfur cap standards—more lenient downstream standards—would have the same effect as announced enforcement tolerances.

EPA is proposing that the values of the downstream cap standards would reflect the testing variability that could reasonably be expected when different laboratories test gasoline for sulfur content, that is, lab-to-lab variability, or reproducibility. For gasoline subject to the 80 ppm refinery-level sulfur cap the proposed downstream standard would be 95 ppm. This difference reflects the lab-to-lab variability established by the American Society for Testing and Materials (ASTM).[96] For gasoline subject to refinery-level sulfur caps higher than 80 ppm, which would be the case for gasoline produced before 2006 and by certain small refiners, the proposed downstream cap would be similarly established by using the most recent available ASTM reproducibility data.

As described in section IV.C.3, EPA is proposing that the cap standards that apply to some small refiners would be higher than the cap standards that apply to refiners generally. The downstream standards that apply to this small refiner gasoline would be correspondingly higher, based on ASTM reproducibility for each refinery's assigned cap. If gasoline produced by a small refiner with a higher cap standard is mixed in the distribution system with other gasoline with a lower cap standard, the entire mixture then would be subject to the higher cap standard. For this reason, EPA is concerned that the small volume of small refinery gasoline could drive up the downstream standard for all gasoline, most of which would have been subject to the much lower national cap standard.

Therefore, EPA is proposing that during the period small refinery individual standards are in effect, PTDs must identify whether gasoline is comprised, in whole or in part, of gasoline produced at a small refinery with a higher sulfur cap standard than the national cap standard, and the level of the downstream cap applicable to the gasoline. A downstream party could rely on the information contained in the PTDs for gasoline received by that party as the basis for whether gasoline contains any small refinery gasoline.

However, as gasoline is mixed, and re-mixed, in downstream pipelines and tanks, the percentage of a particular gasoline that is small refinery gasoline normally will progressively diminish. For this reason EPA also is proposing that a downstream party must classify gasoline as containing no small refinery gasoline if a test result for the gasoline shows a sulfur content below the applicable national downstream cap.

Under these proposed requirements, downstream parties and EPA would know the downstream standard that applies to any particular gasoline. If the gasoline contains no small refiner gasoline, the downstream standard would be based on the national cap. If the gasoline is comprised in whole or in part of small refiner gasoline subject to a higher cap standard, the downstream standard would be based on this higher cap standard. This approach would require regulated parties and EPA to review and rely on the information contained in PTDs.

Following are two examples of how gasoline from small refineries with individual standards (S–RGAS) would be identified downstream of the refinery and how the downstream cap would apply:

(1) In 2005 the national refinery cap standard is 180 ppm. If a small refinery with an individual sulfur cap standard produces a batch of gasoline that contains 175 ppm sulfur, the transfer document that accompanies that batch of gasoline into a pipeline may not indicate the batch contains S–RGAS.

(2) In 2006, when the national downstream cap is 95 ppm, a terminal receives three shipments of gasoline that are identified in the PTD's as S–RGAS subject to downstream per-gallon cap standards of 205, 325 and 410 ppm. The terminal operator combines these shipments in a storage tank. That gasoline mixture is subject to a downstream cap standard of 410 ppm and any PTD subsequently provided to transferees must identify the gasoline as containing S–RGAS and state the gasoline is subject to a downstream cap standard of 410 ppm.

After several additional receipts of gasoline into the storage tank, the terminal operator obtains a test result indicating the sulfur level of the mixture is 90 ppm. Based on this test result, the gasoline mixture becomes subject to the national cap standard of 95 ppm and any PTD subsequently provided to transferees may not state the gasoline contains S–RGAS.

EPA requests comment on these proposed downstream standards. Specifically, we request comment on an alternative whereby gasoline would be presumed to be subject to the national cap downstream standard, unless the responsible regulated party were able to demonstrate through PTDs the presence of small refinery gasoline. EPA also requests comment on any alternatives that would allow enforcement of the national downstream cap standards during the period small refiner individual refinery standards were in effect.

4. What Are the Proposed Testing and Sampling Methods and Requirements?

a. *What Is the Primary Test Method for Gasoline?* We propose that the ASTM standard method D 2622–98 be the primary test method for testing for sulfur in gasoline by refiners and importers. This is the regulatory method under the RFG/CG rule.[97] However, we are requesting comment on whether ASTM method D 5453–93, entitled ''Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence,'' should be the primary method. We are specifically concerned about the suitability of these test methods for sulfur levels between 0–10 ppm, and invite comment on other appropriate test methods, including ASTM D 4045, which is used under the California fuels program for sulfur levels below 10 ppm. We are also requesting

[96] ASTM standard method D–2622–98, entitled ''Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry.'' The California Air Resources Board found nearly identical reproducibility under ASTM D–2622–94, according to a round robin study conducted by ARB and received by EPA Feb. 11, 1999.

[97] See 40 CFR 80.46(a). The proposed rule would update the current method, ASTM D 2622–94.

comment on relative costs of the methods. We believe that ASTM D 5453 would significantly reduce capital costs for test equipment and that operational costs would be similar to ASTM D 2622. A description of these ASTM test methods, as well as other methods discussed later in this section, can be found in Table VI–1, below.

TABLE VI.–1.—ASTM STANDARD TEST METHODS AND PRACTICES DESCRIBED IN THIS SECTION

ASTM No.	Title
D 2622	Standard Test Method for Sulfur in Petroleum Products by Wavelength Dispersive X-ray Fluorescence Spectrometry.
D 4045	Standard Test Method for Sulfur in Petroleum Products by Hydrogenolysis and Rateometric Colorimetry.
D 4057	Standard Practice for Manual Sampling of Petroleum and Petroleum Products.
D 4177	Standard Practice for Automatic Sampling of Petroleum and Petroleum Products.
D 5453	Standard Test Method for Determination of Total Sulfur in Light Hydrocarbons, Motor Fuels and Oils by Ultraviolet Fluorescence.
D 5842	Standard Practice for Sampling and Handling of Fuels for Volatility Measurement.

b. *What Is the Proposed Test Method for Sulfur in Butane?* We are proposing that ASTM D 5623 would be the regulatory method for testing the sulfur content of butane. This is the sulfur test method for butane that the Agency proposed under the RFG/CG rule (proposal published at 62 FR 37338 (July 11, 1997)). However, we received several negative comments regarding this test method in response to our proposal. We are requesting comments on other methods and correlation of those methods to ASTM D 5623. We are also requesting comment on appropriate correlation procedures and other issues such as bias, accuracy, and precision.

c. *Is EPA Proposing a Requirement To Test Every Batch of Gasoline Produced or Imported?* Under today's proposal, all refiners and importers [98] would be required to sample and test the sulfur content of each batch of gasoline produced or imported. Test results would be used to calculate a refiner's or importer's annual average sulfur level. Any batch of gasoline that exceeded the applicable sulfur cap could not be distributed or sold in the U.S., unless it was exempted from this rule, as described later in this section. This ''every-batch'' testing requirement is not a new requirement for RFG refiners and importers. However, it would be a new requirement for refiners and importers of CG.

In the past, CG refiners and importers have been allowed to prepare composite samples of gasoline from multiple gasoline batches and test the composite sample. However, we believe that every-batch sulfur testing by refiners and importers is necessary to ensure compliance with upstream and downstream sulfur caps contained in the proposed rule. We have proposed the use of alternative test methods to reduce the cost of testing. We are requesting comment on this proposed requirement.

i. Butane Blenders' Every-Batch Testing Requirement

Under the RFG rule, refiners that blend butane to previously certified gasoline (PCG) must determine the volume and parameter values of the butane, including sulfur content, by testing the gasoline, before and after blending, and calculating the properties of the butane by subtracting the volume and parameter values of the PCG. For CG only, under certain conditions, we have allowed butane blenders to use the parameter specifications of butane as tested by the butane producer. This includes an assumed sulfur content of 140 ppm. We have allowed this alternative to every-batch testing because of the costs of testing each load of butane.[99]

We are proposing a similar alternative to every-batch testing for butane blenders under today's sulfur program. We propose that butane blenders could use the actual sulfur test result of their suppliers, if the butane contained less than 30 ppm sulfur and if the butane blender undertook a quality assurance program to ensure that the supplier's sampling and testing was accurate. If the butane were tested and found to violate the 30 ppm cap, the butane blender would be in violation for the volume of product that exceeded the 30 ppm cap that was added to gasoline and for any violations of the national downstream cap resulting from the butane sulfur content. We believe this is a fair alternative to every batch testing and the only alternative that gives EPA reasonable ability to monitor compliance. We request comment on this proposal.

ii. Refiners Blending Other Blendstocks into Previously Certified Gasoline

Refiners that blend blendstock into PCG would be required to sample and test each batch of gasoline produced. This would normally include sampling and testing the PCG to determine its sulfur content and volume; then sampling and testing the combined product subsequent to blending; and calculating the sulfur content and volume of the blendstock (which is the blender's batch for annual average compliance and reporting purposes), by subtracting the volume and sulfur content of the PCG from the volume and sulfur content of the combined product. We are proposing to allow such refiners to meet an alternative testing requirement in lieu of testing every batch of gasoline. Provided that the refiner's test result for the sulfur content of each of the blendstocks is less than the national refinery level per-gallon cap standard, a refiner could sample and test each blendstock when received at the refinery, and treat each blendstock receipt as a separate batch for purposes of compliance calculations for the annual average sulfur standard.

d. *What Sampling Methods Are Proposed?* Sampling methods apply to all parties that conduct sampling and testing under the rule. We are proposing requiring the use of sampling methods that were proposed in the July 11, 1997 **Federal Register** notice (62 FR 37338, at 37341–37342, 37375–37376), which proposes modifications to the RFG/CG rule. These sampling methods include ASTM D 4057–95 (manual sampling), D 4177–95 (automatic sampling from pipelines/in-line blending), and ASTM D 5842 (this sampling method is primarily concerned with sampling where gasoline volatility is going to be tested, but it would also be an appropriate sampling method to use when testing for sulfur). We are proposing requiring use of these ASTM methods instead of the methods provided in 40 CFR part 80, Appendix D. That is because the proposed methods have been updated by ASTM, the updates have provided clarification and they have eliminated certain requirements, such as storage tank tap extensions, that are not necessary for sampling light petroleum products such as gasoline.

e. *What Are the Proposed Gasoline Sample Retention Requirements?*

We are proposing a refiner and importer sampling and testing program to establish the sulfur compliance of each batch of gasoline produced or

[98] Except for certain truck importers, as noted above.

[99] In addition, commercial grade butane easily meets conventional gasoline standards, but that is not the case with regard to the proposed gasoline sulfur standards.

imported. However, we are aware of the inherent drawbacks to a self-testing scheme. There is the possibility that a party might sample or test gasoline in a manner not consistent with the required procedures, or that employees might inaccurately record the test results, by mistake or otherwise. Under such a scheme, parties might also attempt to conceal a discovered violation or to save money by not correcting a violation.

In an attempt to address these concerns about self-testing, we considered the option of requiring independent sampling and testing for all gasoline, including conventional gasoline. Under current regulations, only refiners or importers of reformulated gasoline are obligated to do this. However, because of the costs of independent sampling and testing[100] EPA is instead proposing an alternative strategy to help ensure refinery and importer sulfur compliance. Refiners and importers would be required to retain for thirty days a representative sample from each batch of gasoline produced, and to provide such samples to the Agency upon request. By means of this option, EPA could verify the refiner test results.

This limited duration sample retention would be useful to address many of the potential problems concerning a refiner self-testing program. Through this requirement, parties would be faced with the knowledge that EPA could easily and randomly confirm the accuracy of the refiner's test results and could discover unrecorded violations. We believe that this would create an incentive for refiners to sample, test, and record their sulfur results in an accurate and truthful manner.

The Agency also is proposing that refiners be required to certify annually that the samples have been collected in the manner required under the sulfur rule. This requirement is intended to assure that refinery officials insist on accurate and honest sampling and retention of samples at their refineries. We are also proposing that specific procedures be followed by refiners to properly collect retain, and ship the samples in a manner consistent with requirements already imposed or proposed under the RFG program. Under today's proposal, a minimum representative sample of 330 ml of each gasoline batch would need to be retained.[101]

The Agency does not believe that the proposed sulfur rule sample retention requirements would impose an undue financial burden on regulated parties. Many refineries already engage in some sample retention for their own purposes, and the retention procedures proposed in today's proposal would merely require that typical industry retention standards be applied. Shipping samples to us would entail some expense, but this shipping would only occur periodically, and would certainly cost less than hiring an independent laboratory to regularly sample and test gasoline.

The Agency requests comments on the costs and effectiveness of the proposed sample retention requirements, and invites comments on any alternative plan to promote accuracy of refiner self-testing of gasoline for sulfur compliance. In particular, we are interested in information on the cost and effectiveness of a nationwide, independent sampling and testing program

5. What Federal Enforcement Provisions Would Exist for California Gasoline and When Could California Test Methods Be Used to Determine Compliance?

a. *Requirement to Segregate Gasoline and To Use Product Transfer Document Requirements.* Today's proposal would generally exempt California gasoline from regulation under the sulfur rule for the reasons previously described in this preamble. However, today's NPRM does propose two requirements that would apply to some California gasoline. The first would require that gasoline produced outside of California, that is intended for California use, be segregated from all other gasoline at all points in the distribution system. Second, the Agency is proposing that out-of-state producers of gasoline intended for sale in California be required to create PTDs identifying the product as California gasoline, and that such PTDs be provided to all transferees of this gasoline in the distribution system. Such documentation is intended to facilitate our enforcement of the proposed sulfur control program through identifying the gasoline not covered by the federal regulation, even though it is produced in areas otherwise subject to this proposed regulation. This documentation would also assist regulated parties in identifying the gasoline as non-federally regulated to facilitate segregation of California gasoline from federal gasoline.

The sulfur program PTD requirements for California gasoline produced out-of-state should not create any new burdens on regulated parties, since the same requirements currently apply under the RFG program.[102] Today's proposal would incorporate and restate the RFG rule's PTD requirements for this California gasoline. The Agency does not believe that it is necessary to impose additional PTD requirements under the sulfur program, since the California gasoline identification requirements under the RFG rule would also satisfy the identification needs of this rule. Having the same requirements in both rules means that regulated parties that fail to produce and transfer the necessary PTD identification would be in violation of both programs.

b. *Use of California Test Methods for 49 State Gasoline.* As stated previously, we are proposing to exclude gasoline produced in California for California use from federal sulfur standards. However, refineries or importers located in California would have to meet the standards and other requirements with regard to ''federal'' gasoline used outside of California. Nevertheless, EPA is proposing that gasoline produced in California for sale outside of California could be tested for compliance under the federal sulfur rule using the methodologies approved by the ARB, provided that the producer complies with the procedures for such testing as already required under 40 CFR 80.81(h), which permits California test methods not identical to federal test methods to be used for conventional gasoline only.

6. What Are the Proposed Recordkeeping and Reporting Requirements?

a. *What Are the Proposed Product Transfer Document Requirements?* We are proposing that the PTDs that accompany each transfer of custody or title of gasoline that includes gasoline produced by any small refiner subject to sulfur rule individual refinery standards be required to identify the gasoline as such, including the applicable downstream cap, as an aid to enforcing the national downstream cap. Other PTD information is currently required under the RFG/conventional gasoline regulations. We believe that the additional PTD information regarding sulfur compliance required under today's proposal would impose little additional burden on industry. We request comment on this proposed requirement.

[100] See the discussion on this subject in the preamble to the reformulated gasoline program's final rule, 59 FR 7765 (Feb. 16, 1994).

[101] See 40 CFR 80.65(f)(3)(F)(ii), and the Proposed Rule for Modifications to Standards and Requirements for Reformulated and Conventional Gasoline, 62 FR 37337 *et seq*, proposed 40 CFR 80.101(i)(l)(i)(C)(iii).

[102] See CFR 80.81(g).

b. *What Are the Proposed Recordkeeping Requirements?* We are proposing to require that refiners and importers keep and make available to EPA certain records that demonstrate compliance with the sulfur program standards and requirements. The RFG/CG regulations currently require refiners and importers to retain records that include much of the information proposed to be required under today's rule. As a result, we believe that the proposed reporting requirements would impose very little additional burden on these regulated parties.

We are proposing to require all parties in the gasoline distribution system, including refiners, importers, retailers, and all types of distributors to retain PTDs and records of quality assurance programs that parties conduct to establish a defense to downstream violations. All parties in the gasoline distribution system currently are required to keep PTDs for RFG. However, since there are no downstream CG standards, only refiners and importers are required to retain PTDs for conventional gasoline. Because today's proposed sulfur rule, like the RFG rule, includes downstream standards, we believe that a requirement to retain PTDs for all parties in the gasoline distribution system would be appropriate under the sulfur rule. The PTD information would help us identify the source of any gasoline found to be in violation of the sulfur standards. The PTDs would also provide downstream parties with information regarding the applicable downstream standard.

Today's proposal would require parties to keep records for a period of five years, with additional requirements for records pertaining to credits. Records pertaining to credits that were banked and never transferred to another party would need to be retained for five years after the credits are used for compliance purposes. Records pertaining to credits that were transferred would need to be retained by both parties (transferee and transferor) for ten years after the date the credits were generated (which would ensure the records are retained at least years after they are used, since use would have to occur within five years of generation even if the credits were transferred).

Most of the records that would be required to be kept for five years already are subject to that requirement by the RFG/CG rule. Five years is the applicable statute of limitations for the RFG and other fuels programs. See 28 U.S.C. 2462. We request comment on these proposed recordkeeping requirements for refiners, importers and downstream regulated parties. In particular, we request comment on the record retention provisions specific to credits that were transferred. While we recognize that retaining records for ten years could be problematic for both parties, we believe that both parties would need to retain records so that we could be reasonably sure that credits used for compliance were appropriate. An alternative, raised earlier in this proposal, would be to give a more finite life to credits or to require, beginning in 2006, credits to be used in the same year they were generated or transferred. We welcome comments on this solution or any other way in which we can be assured that adequate records would be available should a credit transaction come into question at some date longer than five years after the transaction.

c. *What Are the Proposed Reporting Requirements?* Today's proposed rule would require refiners and importers to submit to us, on an annual basis, a report that demonstrated compliance with the applicable sulfur standards and data on individual batches of gasoline, including batch volume and sulfur content. The RFG/CG programs contain similar reporting requirements. Based on our experience with these programs, we believe that requiring an annual sulfur report and batch information would provide an appropriate and effective means of monitoring compliance with the average standards under the sulfur program. The batch data also would serve to verify that each batch of gasoline met the applicable sulfur cap standard when it left the refinery. In addition, the annual report would provide a vehicle for accounting for any sulfur credits created, sold or used to achieve compliance during the averaging period.

d. *What Are the Proposed Attest Requirements?* We are also proposing to require refiners and importers to arrange for a certified public accountant or certified internal auditor to conduct an annual review of the company's records that form the basis of the annual sulfur compliance report (called an ''attest engagement''). The purpose of the attest engagement is to determine whether representations by the company are supported by the company's internal records. Attest engagements are required under the RFG/CG regulations. We believe that an attestation for sulfur could be included in a refiner's current attest engagement with little additional burden.

We believe that the proposed reporting requirements under today's rule would impose minimal additional reporting burdens on industry while providing us with information necessary to monitor compliance with the sulfur standards. We request comment on these proposed reporting requirements.

7. What Are the Proposed Exemptions for Research, Development, and Testing?

We are proposing to exempt from the sulfur requirements gasoline used for research, development and testing purposes. We recognize that there may be legitimate research programs that require the use of gasoline with higher sulfur levels than those allowed under today's proposed rule. As a result, today's rule contains proposed provisions for obtaining an exemption from the prohibitions for persons distributing, transporting, storing, selling or dispensing gasoline that exceeded the standards, where such gasoline is necessary to conduct a research, development or testing program.

Under the proposal, parties would be required to submit to EPA an application for exemption that would describe the purpose and scope of the program and the reasons why use of the higher sulfur gasoline is necessary. In approving any application, EPA would impose reasonable conditions such as recordkeeping, reporting and volume limitations. We believe that the proposal includes the least onerous requirements for industry that also would ensure that higher sulfur gasoline is used only for legitimate research purposes. We request comment on these proposed provisions. We also request comment on whether in lieu of an approval process, parties should be required to submit the required information to EPA at the start of the program, and annually thereafter, with the condition that EPA could provide a party with written notification in the event the Agency determines the exemption is not justified. We also request comment on whether the regulations should impose a volume limit on the amount of gasoline that could be used in a research program, as a way of minimizing any adverse environmental effects that could result from allowing such an exemption from the sulfur requirements.

8. What Are the Proposed Liability and Penalty Provisions for Noncompliance?

Today's proposed rule contains provisions for liability and penalties that are similar to the liability and penalty provisions of the RFG and other fuels regulations.[103] Under the proposed

[103] See section 80.5 (penalties for fuels violations); section 80.23 (liability for lead violations); section 80.28 (liability for volatility violations); section 80.30 (liability for diesel violations); section 80.79 (liability for violation of

rule, regulated parties would be liable for committing certain prohibited acts, such as selling or distributing gasoline that does not meet the sulfur standards, or causing others to commit prohibited acts. In addition, parties would be liable for a failure to meet certain affirmative requirements, or causing others to fail to meet affirmative requirements. For example, persons who produce or import gasoline would be liable for a failure to fulfill any of the requirements for refiners and importers, including the sampling and testing requirements, the reporting and attest audit requirements, the averaging requirements, the small refinery requirements, and the credit creation and trading requirements. In such cases the regulated party would also be liable for any violation of the sulfur standard based on corrected information. All parties in the gasoline distribution system, including refiners, importers, distributors, carriers, retailers, and wholesale purchaser-consumers, would be liable for a failure to fulfill the recordkeeping requirements and the PTD requirements.

a. *Presumptive Liability Scheme of Current EPA Fuels Programs.* Current EPA fuels programs include a presumptive liability scheme for violations of prohibited acts. Under this approach, presumptive liability is imposed on two types of parties: (1) That party in the gasoline distribution system that controls the facility where the violation was found or had occurred; and (2) those parties, typically upstream in the gasoline distribution system from the initially listed party, (such as the refiner, reseller, and any distributor of the gasoline), whose prohibited activities could have caused the program non-conformity to exist.[104] This presumptive liability scheme has worked well in enabling us to enforce our fuels programs, since it creates comprehensive liability for substantially all the potentially responsible parties. The presumptions of liability may be rebutted by establishing an affirmative defense.

To clarify the inclusive nature of these presumptive liability schemes, today's proposed rule would explicitly include causing another person to commit a prohibited act and causing the presence of non-conforming gasoline to be in the distribution system as prohibitions. This is consistent with the provisions and implementation of other fuels programs.

Today's proposed rule, therefore, provides that most parties involved in the chain of distribution would be subject to a presumption of liability for actions prohibited, including causing non-conforming gasoline to be in the distribution system and causing violations by other parties. Like the other fuels regulations, a refiner also would be subject to a presumption of vicarious liability for violations by any downstream facility that displays the refiner's brand name, based on the refiner's ability to exercise control at these facilities. Carriers, however, would be presumed liable only for violations arising from product under their control or custody, and not for causing non-conforming gasoline to be in the distribution system, except where we have specific evidence of causation.

b. *Affirmative Defenses for Each Presumptively Liable Party.* The proposal includes affirmative defenses for each party that is deemed presumptively liable for a violation, and all presumptions of liability are refutable. The proposed defenses are similar to the defenses available to parties for violations of the RFG regulations. We believe that these defense elements set forth reasonably attainable criteria to rebut a presumption of liability. The defenses include a demonstration that: (1) the party did not cause the violation; and (2) except for retailers and wholesale purchaser-consumers, the party conducted a quality assurance program. For parties other than tank truck carriers, the quality assurance program would be required to include periodic sampling and testing of the gasoline. For tank truck carriers, the quality assurance program would not need to include periodic sampling and testing, but in lieu of sampling and testing, the carrier would be required to demonstrate evidence of an oversight program for monitoring compliance, such as appropriate guidance to drivers on compliance with applicable requirements and the periodic review of records concerning gasoline quality and delivery.

As in the other fuels regulations, branded refiners would be subject to more stringent standards for establishing a defense because of the control such refiners have over branded downstream parties. Under today's rule, in addition to the other defense elements, branded refiners would be required to show that the violation was caused by an action by another person in violation of law, an action by another person in violation of a contractual agreement with the refiner, or the action of a distributor not subject to a contract with the refiner but engaged by the refiner for the transportation of the gasoline.

Based on experience with other fuels programs, we believe that a presumptive liability approach would increase the likelihood of identifying persons who cause violations of the sulfur standards. We normally do not have the information necessary to establish the cause of a violation found at a facility downstream of the refiner or importer. We believe that those persons who actually handle the gasoline are in the best position to identify the cause of the violation, and that a refutable presumption of liability would provide an incentive for parties to be forthcoming with information regarding the cause of the violation. In addition to identifying the party that caused the violation, providing evidence to rebut a presumption of liability would serve to establish a defense for the parties who are not responsible. Presumptive liability is familiar to both industry and to us, and we believe that this approach would make the most efficient use of EPA's enforcement resources. For these reasons, we are proposing a liability scheme for the sulfur program based on a presumption of liability. We request comment on the proposed liability provisions.

c. *Penalties for Violations.* Section 211(d)(1) of the CAA provides for penalties for violations of the fuels regulations.[105] Today's rule proposes penalty provisions that would apply this CAA penalty provision to the sulfur rule. The proposed provisions would subject any person who violates any requirement or prohibition of the sulfur rule to a civil penalty of up to $27,500 for every day of each such violation and the amount of economic benefit or savings resulting from the violation. A violation of the applicable average sulfur standard would constitute a separate day of violation for each day in the averaging period. A violation of a sulfur cap standard would constitute a

RFG prohibited acts); section 80.80 (penalties for RFG/conventional gasoline violations).

[104] Additional type of liability, vicarious liability, is also imposed on branded refiners under these fuels programs.

[105] Section 211(d)(1) reads, in pertinent part:

(d)(1) Civil Penalties.—Any person who violates * * * the regulations prescribed under subsection (c) * * * of this section * * * shall be liable to the United States for a civil penalty of not more than the sum of $25,000 for every day of such violation and the amount of economic benefit or saving resulting from the violation. * * * Any violation with respect to a regulation prescribed under subsection (c) * * * of this section which establishes a regulatory standard based upon a multi-day averaging period shall constitute a separate day of violation for each and every day in the averaging period. * * *

Pursuant to the Debt Collection Improvement Act of 1996 (31 U.S.C. 3701 note), the maximum penalty amount prescribed in section 211(d)(1) of the CAA was increased to $27,500. (See 40 CFR part 19.)

separate day of violation for each day the gasoline giving rise to the violation remained in the gasoline distribution system. The length of time the gasoline in question remained in the distribution system would be deemed to be twenty-five days unless there is evidence that the gasoline remained in the gasoline distribution system for fewer than or more than twenty-five days. The penalty provisions proposed in today's rule are similar to the penalty provisions for violations of the RFG regulations. EPA requests comment on these provisions.

9. How Would Compliance With the Sulfur Standards Be Determined?

We have often used a variety of evidence to establish non-compliance with requirements imposed under our current fuels regulations. Test results of the content of gasoline have been used to establish violations, both in situations where the sample has been taken from the facility at which the violation is found, and where the sample has been obtained from other parties' facilities when such test results have had probative value of the gasoline's characteristics at points upstream or downstream. The Agency has also commonly used documentary evidence to establish non-compliance or a party's liability for non-compliance. Typical documentary evidence has included transfer documents identifying the gasoline as inappropriate for the facility it is being delivered to, or identifying parties having connection with the non-complying gasoline.

a. *What Evidence Could Be Used to Establish Sulfur Rule Violations and Liability for these Violations?* A recent EPA Environmental Appeals Board decision, (In re: Commercial Cartage Company, Docket No. CAA–93–H–002, CAA Appeal No. 97–9) (the ''Cartage'' decision), interpreted the regulatory language of one of EPA's fuels programs as restricting the evidence that the Agency may use in establishing a violation of a standard under that program. Under the Cartage decision, in order to establish the existence of a violation of the gasoline volatility standards [106] at a particular carrier or retail outlet facility, we would have to produce non-compliant test results obtained only by using the regulatory method and only from a sample taken from the facility itself. Other potentially persuasive evidence establishing volatility standard violations would not be permitted under the Cartage decision's interpretation of the volatility rule.[107]

We believe that it would best serve the purposes of the proposed sulfur rule to not limit the evidence that may be used to show whether a violation occurred or liability for that violation. Our enforcement experience in other programs has shown that the Cartage-permitted evidence (test results from samples taken only from a particular facility, and using only the regulatory test methods) often does not exist, while other persuasive evidence of the existence of the violations does exist. If we are not able to use other forms of persuasive evidence to establish violations or other necessary facts short of test results such as those permitted by the volatility regulations under the Cartage interpretation, violators will continue to avoid liability for their actions.

To ensure that evidence with probative value could be used under the sulfur rule, the Agency is making explicit in today's proposal that any probative evidence could be used to establish compliance or non-compliance with the sulfur standards and requirements and liability for non-compliance. This would not remove or change the obligation on refiners and importers to perform testing on each batch of gasoline using the procedures authorized under these regulations. Compliance or non-compliance with sulfur standards would continue to be based on regulatory test methods. However, other probative evidence could be used to determine compliance with sulfur standards if the evidence is relevant to whether the sulfur content would have been in compliance if the appropriate sampling and testing methodologies had been performed.

Under today's proposal, the permitted probative evidence specifically includes information obtained from any source or any location, since Agency enforcement experience has proven the value of such widely-obtained material. Respondents in EPA enforcement actions would have the same right to present other evidence of compliance with the sulfur rule as the Agency would have to establish non-compliance.

VII. Public Participation

We received many comments from a range of interested parties on our Tier 2 Report to Congress. We have also received comments as part of the our outreach to small entities (see section V.B.). These comments have been very valuable in developing this proposal, and we look forward to additional comment during the rulemaking process. You can find comments on the issuance of Tier 2 standards and gasoline sulfur control we received prior to this proposed action in the rulemaking docket, and many of them are discussed in the context of various issues in this preamble. We have considered comments received during the development of the proposal and have addressed a number of them in today's document.

A. Comments and the Public Docket

Publication of this document opens a formal comment period on this proposal. You may submit comments during the period indicated under **DATES** above. The Agency encourages all parties that have an interest in the program described in this document to offer comment on all aspects of the action. Throughout this proposal you will find requests for specific comment on various topics.

The most useful comments are those supported by appropriate and detailed rationales, data, and analyses. We also encourage commenters who disagree with the proposed program to suggest and analyze alternate approaches to meeting the air quality goals of this proposed program. You should send all comments, except those containing proprietary information, to the EPA's Air Docket (see **ADDRESSES**) before the date specified above for the end of the comment period.

Commenters who wish to submit proprietary information for consideration should clearly separate such information from other comments. Such submissions should be labeled as ''Confidential Business Information'' and be sent directly to the contact person listed (see **FOR FURTHER INFORMATION CONTACT**), not to the public docket. This will help ensure that proprietary information is not placed in the public docket. If a commenter wants EPA to use a submission of confidential information as part of the basis for the final rule, then a nonconfidential version of the document that summarizes the key data or information must be sent to the docket.

We will disclose information covered by a claim of confidentiality only to the extent allowed by the procedures set forth in 40 CFR Part 2. If no claim of confidentiality accompanies a submission when we receive it, we will make it available to the public without further notice to the commenter.

B. Public Hearings

We will hold four public hearings as noted under ''DATES'' above. If you would like to present testimony at the

[106] EPA's gasoline volatility regulations are found at 40 CFR 80.27 and 80.28.

[107] See 40 CFR 80.27(b) and 80.28(b) and (e).